EXELON CORP
Form 10-Q
May 02, 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 March 31, 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	52-2297449

	(a Delaware limited liability company) 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 March 31, 2018 was:

Exelon Corporation Common Stock, without par value	965,381,919
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,264
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
BondCo	RSB BondCo LLC
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
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 Delievery 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
CAISO	California ISO
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	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
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 BGS
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
DSP	Default Service Provider
EDF	Electricite de France SA and its subsidiaries
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
Integrys	Integrys Energy Services, Inc.
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
PAPUC	Pennsylvania Public Utility Commission
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
Preferred Stock	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share
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
RGGI	Regional Greenhouse Gas Initiative
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
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SGIG	Smart Grid Investment Grant from DOE
SILO	Sale-In, Lease-Out
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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 March 31, 2018	2017
Operating revenues		
Competitive businesses revenues	$5,113	$4,550
Rate-regulated utility revenues	4,570	4,118
Revenues from alternative revenue programs	10	79
Total operating revenues	9,693	8,747
Operating expenses		
Competitive businesses purchased power and fuel	3,289	2,795
Rate-regulated utility purchased power and fuel	1,438	1,104
Operating and maintenance	2,384	2,438
Depreciation and amortization	1,091	896
Taxes other than income	446	436
Total operating expenses	8,648	7,669
Gain on sales of assets and businesses	56	4
Bargain purchase gain	—	226
Operating income	1,101	1,308
Other income and (deductions)		
Interest expense, net	(365)	(363)
Interest expense to affiliates	(6)	(10)
Other, net	(28)	257
Total other income and (deductions)	(399)	(116)
Income before income taxes	702	1,192
Income taxes	59	211
Equity in losses of unconsolidated affiliates	(7)	(10)
Net income	636	971
Net income (loss) attributable to noncontrolling interests	51	(19)
Net income attributable to common shareholders	$585	$990
Comprehensive income, net of income taxes		
Net income	$636	$971
Other comprehensive income (loss), net of income taxes		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	(17)	(13)
Actuarial loss reclassified to periodic benefit cost	61	49
Pension and non-pension postretirement benefit plan valuation adjustment	18	(59)
Unrealized gain on cash flow hedges	8	6
Unrealized gain on investments in unconsolidated affiliates	1	3
Unrealized gain on foreign currency translation	1	1
Unrealized gain on marketable securities	—	1
Other comprehensive income (loss)	72	(12)
Comprehensive income	708	959
Comprehensive income (loss) attributable to noncontrolling interests	52	(21)

Comprehensive income attributable to common shareholders	$656	$980
Average shares of common stock outstanding:		
Basic	966	928
Diluted	968	930
Earnings per average common share:		
Basic	$0.61	$1.07
Diluted	$0.60	$1.06
Dividends declared per common share	$0.35	$0.33

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$636	$971
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,501	1,274
Impairment of long-lived assets and losses on regulatory assets	—	10
Gain on sales of assets and businesses	(56)	(4)
Bargain purchase gain	—	(226)
Deferred income taxes and amortization of investment tax credits	(14)	185
Net fair value changes related to derivatives	259	47
Net realized and unrealized gains (losses) on nuclear decommissioning trust fund investments	68	(175)
Other non-cash operating activities	240	118
Changes in assets and liabilities:		
Accounts receivable	133	291
Inventories	167	109
Accounts payable and accrued expenses	(451)	(728)
Option premiums paid, net	(27)	(6)
Collateral posted, net	(214)	(110)
Income taxes	86	50
Pension and non-pension postretirement benefit contributions	(331)	(307)
Other assets and liabilities	(495)	(425)
Net cash flows provided by operating activities	1,502	1,074
Cash flows from investing activities		
Capital expenditures	(1,880)	(2,009)
Proceeds from nuclear decommissioning trust fund sales	1,189	1,767
Investment in nuclear decommissioning trust funds	(1,248)	(1,833)
Acquisition of businesses, net	—	(212)
Proceeds from sales of assets and businesses	79	22
Other investing activities	3	(18)
Net cash flows used in investing activities	(1,857)	(2,283)
Cash flows from financing activities		
Changes in short-term borrowings	726	721
Proceeds from short-term borrowings with maturities greater than 90 days	1	560
Repayments on short-term borrowings with maturities greater than 90 days	(1)	(500)
Issuance of long-term debt	1,130	763
Retirement of long-term debt	(1,241)	(65)
Dividends paid on common stock	(333)	(303)
Proceeds from employee stock plans	12	12
Other financing activities	(30)	(4)
Net cash flows provided by financing activities	264	1,184
Decrease in cash, cash equivalents and restricted cash	(91)	(25)
Cash, cash equivalents and restricted cash at beginning of period	1,190	914

Cash, cash equivalents and restricted cash at end of period	$1,099	$889

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 787	$ 898
Restricted cash and cash equivalents	209	207
Accounts receivable, net		
Customer	4,190	4,445
Other	1,103	1,132
Mark-to-market derivative assets	978	976
Unamortized energy contract assets	55	60
Inventories, net		
Fossil fuel and emission allowances	180	340
Materials and supplies	1,291	1,311
Regulatory assets	1,245	1,267
Other	1,495	1,260
Total current assets	11,533	11,896
Property, plant and equipment, net	74,711	74,202
Deferred debits and other assets		
Regulatory assets	8,063	8,021
Nuclear decommissioning trust funds	13,149	13,272
Investments	640	640
Goodwill	6,677	6,677
Mark-to-market derivative assets	527	337
Unamortized energy contract assets	385	395
Other	1,333	1,330
Total deferred debits and other assets	30,774	30,672
Total assets[a]	$ 117,018	$ 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)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$1,654	$929
Long-term debt due within one year	1,203	2,088
Accounts payable	3,207	3,532
Accrued expenses	1,569	1,837
Payables to affiliates	5	5
Regulatory liabilities	522	523
Mark-to-market derivative liabilities	415	232
Unamortized energy contract liabilities	202	231
Renewable energy credit obligation	333	352
PHI merger related obligation	87	87
Other	956	982
Total current liabilities	10,153	10,798
Long-term debt	32,905	32,176
Long-term debt to financing trusts	389	389
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,344	11,235
Asset retirement obligations	10,126	10,029
Pension obligations	3,433	3,736
Non-pension postretirement benefit obligations	2,114	2,093
Spent nuclear fuel obligation	1,151	1,147
Regulatory liabilities	9,724	9,865
Mark-to-market derivative liabilities	468	409
Unamortized energy contract liabilities	579	609
Other	2,067	2,097
Total deferred credits and other liabilities	41,006	41,220
Total liabilities[(a)]	84,453	84,583
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 965 shares and 963 shares outstanding at March 31, 2018 and December 31, 2017, respectively)	18,973	18,964
Treasury stock, at cost (2 shares at March 31, 2018 and December 31, 2017)	(123)	(123)
Retained earnings	14,346	14,081
Accumulated other comprehensive loss, net	(2,965)	(3,026)
Total shareholders' equity	30,231	29,896
Noncontrolling interests	2,334	2,291
Total equity	32,565	32,187
Total liabilities and shareholders' equity	$117,018	$116,770

(a) Exelon's consolidated assets include $9,727 million and $9,597 million at March 31, 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 $3,556 million and $3,618 million at March 31, 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.

See the Combined Notes to Consolidated Financial Statements

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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	—	—	—	585	—	51	636
Long-term incentive plan activity	1,685	(3)	—	—	—	—	(3)
Employee stock purchase plan issuances	361	12	—	—	—	—	12
Changes in equity of noncontrolling interests	—	—	—	—	—	(9)	(9)
Common stock dividends	—	—	—	(334)	—	—	(334)
Other comprehensive income, net of income taxes	—	—	—	—	71	1	72
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	—	—	14	(10)	—	4
Balance, March 31, 2018	967,214	$18,973	$(123)	$14,346	$(2,965)	$2,334	$32,565

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Operating revenues	$5,114	$4,548
Operating revenues from affiliates	398	330
Total operating revenues	5,512	4,878
Operating expenses		
Purchased power and fuel	3,289	2,796
Purchased power and fuel from affiliates	4	2
Operating and maintenance	1,178	1,313
Operating and maintenance from affiliates	161	179
Depreciation and amortization	448	302
Taxes other than income	138	143
Total operating expenses	5,218	4,735
Gain on sales of assets and businesses	53	4
Bargain purchase gain	—	226
Operating income	347	373
Other income and (deductions)		
Interest expense, net	(91)	(90)
Interest expense to affiliates	(10)	(10)
Other, net	(44)	259
Total other income and (deductions)	(145)	159
Income before income taxes	202	532
Income taxes	9	123
Equity in losses of unconsolidated affiliates	(7)	(10)
Net income	186	399
Net income (loss) attributable to noncontrolling interests	50	(19)
Net income attributable to membership interest	$136	$418
Comprehensive income, net of income taxes		
Net income	$186	$399
Other comprehensive income (loss), net of income taxes		
Unrealized gain on cash flow hedges	7	6
Unrealized gain on investments in unconsolidated affiliates	1	4
Unrealized (loss) gain on foreign currency translation	(1)	1
Other comprehensive income	7	11
Comprehensive income	193	410
Comprehensive income (loss) attributable to noncontrolling interests	51	(21)
Comprehensive income attributable to membership interest	$142	$431

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$186	$399
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	858	678
Impairment of long-lived assets	—	10
Gain on sales of assets and businesses	(53)	(4)
Bargain purchase gain	—	(226)
Deferred income taxes and amortization of investment tax credits	(68)	108
Net fair value changes related to derivatives	264	51
Net realized and unrealized gains on nuclear decommissioning trust fund investments	68	(175)
Other non-cash operating activities	45	(10)
Changes in assets and liabilities:		
Accounts receivable	194	173
Receivables from and payables to affiliates, net	(15)	23
Inventories	122	81
Accounts payable and accrued expenses	(317)	(236)
Option premiums paid, net	(27)	(6)
Collateral posted, net	(214)	(102)
Income taxes	79	(81)
Pension and non-pension postretirement benefit contributions	(125)	(110)
Other assets and liabilities	(142)	(153)
Net cash flows provided by operating activities	855	420
Cash flows from investing activities		
Capital expenditures	(628)	(625)
Proceeds from nuclear decommissioning trust fund sales	1,189	1,767
Investment in nuclear decommissioning trust funds	(1,248)	(1,833)
Acquisition of businesses, net	—	(212)
Proceeds from sales of assets and businesses	79	22
Other investing activities	(7)	(29)
Net cash flows used in investing activities	(615)	(910)
Cash flows from financing activities		
Changes in short-term borrowings	165	(42)
Proceeds from short-term borrowings with maturities greater than 90 days	1	60
Repayments of short-term borrowings with maturities greater than 90 days	(1)	—
Issuance of long-term debt	4	762
Retirement of long-term debt	(29)	(30)
Changes in Exelon intercompany money pool	—	(1)
Distributions to member	(188)	(164)
Other financing activities	(9)	(3)

Net cash flows (used in) provided by financing activities	(57)	582
Increase in cash, cash equivalents and restricted cash	183	92
Cash, cash equivalents and restricted cash at beginning of period	554	448
Cash, cash equivalents and restricted cash at end of period	$737	$540

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

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$610	$ 416
Restricted cash and cash equivalents	127	138
Accounts receivable, net		
Customer	2,478	2,697
Other	294	321
Mark-to-market derivative assets	978	976
Receivables from affiliates	153	140
Unamortized energy contract assets	55	60
Inventories, net		
Fossil fuel and emission allowances	151	264
Materials and supplies	916	937
Other	1,122	933
Total current assets	6,884	6,882
Property, plant and equipment, net	24,714	24,906
Deferred debits and other assets		
Nuclear decommissioning trust funds	13,149	13,272
Investments	431	433
Goodwill	47	47
Mark-to-market derivative assets	527	334
Prepaid pension asset	1,571	1,502
Unamortized energy contract assets	385	395
Deferred income taxes	10	16
Other	657	670
Total deferred debits and other assets	16,777	16,669
Total assets[a]	$48,375	$ 48,457

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

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$166	$2
Long-term debt due within one year	373	346
Accounts payable	1,447	1,773
Accrued expenses	951	1,022
Payables to affiliates	114	123
Borrowings from Exelon intercompany money pool	54	54
Mark-to-market derivative liabilities	391	211
Unamortized energy contract liabilities	39	43
Renewable energy credit obligation	333	352
Other	288	265
Total current liabilities	4,156	4,191
Long-term debt	7,685	7,734
Long-term debt to affiliate	907	910
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,749	3,811
Asset retirement obligations	9,941	9,844
Non-pension postretirement benefit obligations	911	916
Spent nuclear fuel obligation	1,151	1,147
Payables to affiliates	2,970	3,065
Mark-to-market derivative liabilities	221	174
Unamortized energy contract liabilities	40	48
Other	686	658
Total deferred credits and other liabilities	19,669	19,663
Total liabilities[(a)]	32,417	32,498
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,357	9,357
Undistributed earnings	4,303	4,349
Accumulated other comprehensive loss, net	(34)	(37)
Total member's equity	13,626	13,669
Noncontrolling interests	2,332	2,290
Total equity	15,958	15,959
Total liabilities and equity	$48,375	$48,457

(a) Generation's consolidated assets include $9,688 million and $9,556 million at March 31, 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 $3,461 million and $3,516 million at March 31, 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.

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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	—	136	—	50	186
Changes in equity of noncontrolling interests	—	—	—	(9)	(9)
Distributions to member	—	(188)	—	—	(188)
Other comprehensive income, net of income taxes	—	—	6	1	7
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, March 31, 2018	$9,357	$ 4,303	$ (34)	$ 2,332	$15,958

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$1,493	$1,279
Revenues from alternative revenue programs	5	14
Operating revenues from affiliates	14	5
Total operating revenues	1,512	1,298
Operating expenses		
Purchased power	411	329
Purchased power from affiliate	194	5
Operating and maintenance	253	307
Operating and maintenance from affiliate	60	63
Depreciation and amortization	228	208
Taxes other than income	77	72
Total operating expenses	1,223	984
Gain on sales of assets	3	—
Operating income	292	314
Other income and (deductions)		
Interest expense, net	(86)	(82)
Interest expense to affiliates	(3)	(3)
Other, net	8	4
Total other income and (deductions)	(81)	(81)
Income before income taxes	211	233
Income taxes	46	92
Net income	$165	$141
Comprehensive income	$165	$141

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$165	$141
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	228	208
Deferred income taxes and amortization of investment tax credits	50	137
Other non-cash operating activities	46	31
Changes in assets and liabilities:		
Accounts receivable	39	92
Receivables from and payables to affiliates, net	(19)	(16)
Inventories	5	4
Accounts payable and accrued expenses	(158)	(236)
Collateral posted, net	(3)	(7)
Income taxes	(5)	(34)
Pension and non-pension postretirement benefit contributions	(38)	(35)
Other assets and liabilities	(176)	(49)
Net cash flows provided by operating activities	134	236
Cash flows from investing activities		
Capital expenditures	(531)	(626)
Other investing activities	8	7
Net cash flows used in investing activities	(523)	(619)
Cash flows from financing activities		
Changes in short-term borrowings	317	365
Issuance of long-term debt	800	—
Retirement of long-term debt	(700)	—
Contributions from parent	113	100
Dividends paid on common stock	(114)	(105)
Other financing activities	(9)	(1)
Net cash flows provided by financing activities	407	359
Increase (Decrease) in cash, cash equivalents and restricted cash	18	(24)
Cash, cash equivalents and restricted cash at beginning of period	144	58
Cash, cash equivalents and restricted cash at end of period	$162	$34

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

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$70	$ 76
Restricted cash	9	5
Accounts receivable, net		
Customer	485	559
Other	290	266
Receivables from affiliates	28	13
Inventories, net	146	152
Regulatory assets	226	225
Other	82	68
Total current assets	1,336	1,364
Property, plant and equipment, net	21,010	20,723
Deferred debits and other assets		
Regulatory assets	1,125	1,054
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,464	2,528
Prepaid pension asset	1,177	1,188
Other	259	238
Total deferred debits and other assets	7,656	7,639
Total assets	$30,002	$ 29,726

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

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$317	$—
Long-term debt due within one year	440	840
Accounts payable	491	568
Accrued expenses	198	327
Payables to affiliates	70	74
Customer deposits	111	112
Regulatory liabilities	212	249
Mark-to-market derivative liability	24	21
Other	82	103
Total current liabilities	1,945	2,294
Long-term debt	7,254	6,761
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,539	3,469
Asset retirement obligations	111	111
Non-pension postretirement benefits obligations	215	219
Regulatory liabilities	6,212	6,328
Mark-to-market derivative liability	243	235
Other	572	562
Total deferred credits and other liabilities	10,892	10,924
Total liabilities	20,296	20,184
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	6,935	6,822
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,822	2,771
Total shareholders' equity	9,706	9,542
Total liabilities and shareholders' equity	$30,002	$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	—	—	165	—	165
Appropriation of retained earnings for future dividends	—	—	(165)	165	—
Common stock dividends	—	—	—	(114)	(114)
Contributions from parent	—	113	—	—	113
Balance, March 31, 2018	$ 1,588	$ 6,935	$ (1,639)	$ 2,822	$ 9,706

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$633	$589
Natural gas operating revenues	232	206
Revenues from alternative revenue programs	(1)	—
Operating revenues from affiliates	2	1
Total operating revenues	866	796
Operating expenses		
Purchased power	199	156
Purchased fuel	98	86
Purchased power from affiliate	36	45
Operating and maintenance	233	174
Operating and maintenance from affiliates	42	34
Depreciation and amortization	75	71
Taxes other than income	41	38
Total operating expenses	724	604
Operating income	142	192
Other income and (deductions)		
Interest expense, net	(30)	(28)
Interest expense to affiliates	(3)	(3)
Other, net	2	2
Total other income and (deductions)	(31)	(29)
Income before income taxes	111	163
Income taxes	(2)	36
Net income	$113	$127
Comprehensive income	$113	$127

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$113	$127
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	75	71
Deferred income taxes and amortization of investment tax credits	(4)	24
Other non-cash operating activities	21	23
Changes in assets and liabilities:		
Accounts receivable	(51)	(25)
Receivables from and payables to affiliates, net	7	(10)
Inventories	12	19
Accounts payable and accrued expenses	6	(40)
Income taxes	5	25
Pension and non-pension postretirement benefit contributions	(24)	(23)
Other assets and liabilities	(141)	(85)
Net cash flows provided by operating activities	19	106
Cash flows from investing activities		
Capital expenditures	(217)	(201)
Changes in Exelon intercompany money pool	—	131
Other investing activities	2	1
Net cash flows used in investing activities	(215)	(69)
Cash flows from financing activities		
Changes in short-term borrowings	220	—
Issuance of long-term debt	325	—
Retirement of long-term debt	(500)	—
Changes in Exelon intercompany money pool	194	—
Dividends paid on common stock	(287)	(72)
Other financing activities	(5)	—
Net cash flows used in financing activities	(53)	(72)
Decrease in cash, cash equivalents and restricted cash	(249)	(35)
Cash, cash equivalents and restricted cash at beginning of period	275	67
Cash, cash equivalents and restricted cash at end of period	$26	$32

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

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$21	$ 271
Restricted cash and cash equivalents	5	4
Accounts receivable, net		
Customer	349	327
Other	117	105
Inventories, net		
Fossil fuel	16	31
Materials and supplies	33	30
Prepaid utility taxes	97	8
Regulatory assets	78	29
Other	20	17
Total current assets	736	822
Property, plant and equipment, net	8,176	8,053
Deferred debits and other assets		
Regulatory assets	408	381
Investments	25	25
Receivable from affiliates	505	537
Prepaid pension asset	359	340
Other	9	12
Total deferred debits and other assets	1,306	1,295
Total assets	$10,218	$ 10,170

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

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$220	$ —
Long-term debt due within one year	—	500
Accounts payable	379	370
Accrued expenses	91	114
Payables to affiliates	59	53
Borrowings from Exelon intercompany money pool	194	—
Customer deposits	66	66
Regulatory liabilities	117	141
Other	29	23
Total current liabilities	1,155	1,267
Long-term debt	2,723	2,403
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,824	1,789
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	288
Regulatory liabilities	529	549
Other	85	86
Total deferred credits and other liabilities	2,753	2,739
Total liabilities	6,815	6,593
Commitments and contingencies		
Shareholder’s equity		
Common stock	2,489	2,489
Retained earnings	914	1,087
Accumulated other comprehensive income, net	—	1
Total shareholder’s equity	3,403	3,577
Total liabilities and shareholder's equity	$10,218	$ 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	—	113	—	113
Common stock dividends	—	(287)	—	(287)
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	1	(1)	—
Balance, March 31, 2018	$ 2,489	$ 914	$ —	$ 3,403

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$654	$640
Natural gas operating revenues	330	271
Revenues from alternative revenue programs	(13)	35
Operating revenues from affiliates	6	5
Total operating revenues	977	951
Operating expenses		
Purchased power	192	133
Purchased fuel	123	83
Purchased power from affiliate	65	134
Operating and maintenance	184	148
Operating and maintenance from affiliates	37	35
Depreciation and amortization	134	128
Taxes other than income	65	62
Total operating expenses	800	723
Operating income	177	228
Other income and (deductions)		
Interest expense, net	(25)	(23)
Interest expense to affiliates	—	(4)
Other, net	4	4
Total other income and (deductions)	(21)	(23)
Income before income taxes	156	205
Income taxes	28	80
Net income	$128	$125
Comprehensive income	$128	$125

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$128	$125
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	134	128
Deferred income taxes and amortization of investment tax credits	22	72
Other non-cash operating activities	20	24
Changes in assets and liabilities:		
Accounts receivable	(32)	(7)
Receivables from and payables to affiliates, net	—	(7)
Inventories	20	17
Accounts payable and accrued expenses	(9)	(81)
Income taxes	14	33
Pension and non-pension postretirement benefit contributions	(45)	(44)
Other assets and liabilities	61	(52)
Net cash flows provided by operating activities	313	208
Cash flows from investing activities		
Capital expenditures	(224)	(206)
Other investing activities	1	4
Net cash flows used in investing activities	(223)	(202)
Cash flows from financing activities		
Changes in short-term borrowings	(32)	50
Dividends paid on common stock	(52)	(49)
Net cash flows (used in) provided by financing activities	(84)	1
Increase in cash, cash equivalents and restricted cash	6	7
Cash, cash equivalents and restricted cash at beginning of period	18	50
Cash, cash equivalents and restricted cash at end of period	$24	$57

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

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$22	$ 17
Restricted cash and cash equivalents	2	1
Accounts receivable, net		
Customer	394	375
Other	91	94
Receivables from affiliates	—	1
Inventories, net		
Gas held in storage	12	37
Materials and supplies	45	40
Prepaid utility taxes	35	69
Regulatory assets	149	174
Other	5	3
Total current assets	755	811
Property, plant and equipment, net	7,725	7,602
Deferred debits and other assets		
Regulatory assets	391	397
Investments	5	5
Prepaid pension asset	313	285
Other	6	4
Total deferred debits and other assets	715	691
Total assets	$9,195	$ 9,104

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

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$45	$ 77
Accounts payable	253	265
Accrued expenses	162	164
Payables to affiliates	51	52
Customer deposits	118	116
Regulatory liabilities	102	62
Other	26	24
Total current liabilities	757	760
Long-term debt	2,578	2,577
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,286	1,244
Asset retirement obligations	22	23
Non-pension postretirement benefits obligations	199	202
Regulatory liabilities	1,083	1,101
Other	53	56
Total deferred credits and other liabilities	2,643	2,626
Total liabilities	5,978	5,963
Commitments and contingencies		
Shareholders' equity		
Common stock	1,605	1,605
Retained earnings	1,612	1,536
Total shareholders' equity	3,217	3,141
Total liabilities and shareholders' equity	$9,195	$ 9,104

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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	—	128	128
Common stock dividends	—	(52)	(52)
Balance, March 31, 2018	$ 1,605	$ 1,612	$ 3,217

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$1,151	$1,067
Natural gas operating revenues	78	66
Revenues from alternative revenue programs	18	30
Operating revenues from affiliates	4	12
Total operating revenues	1,251	1,175
Operating expenses		
Purchased power	374	288
Purchased fuel	41	29
Purchased power and fuel from affiliates	105	144
Operating and maintenance	271	223
Operating and maintenance from affiliates	38	33
Depreciation, amortization and accretion	183	167
Taxes other than income	113	111
Total operating expenses	1,125	995
Operating income	126	180
Other income and (deductions)		
Interest expense, net	(63)	(62)
Other, net	11	13
Total other income and (deductions)	(52)	(49)
Income before income taxes	74	131
Income taxes	9	(9)
Net income	$65	$140
Comprehensive income	$65	$140

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$65	$140
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	183	167
Deferred income taxes and amortization of investment tax credits	17	13
Other non-cash operating activities	53	(8)
Changes in assets and liabilities:		
Accounts receivable	(9)	68
Receivables from and payables to affiliates, net	10	(8)
Inventories	4	(11)
Accounts payable and accrued expenses	44	(81)
Income taxes	(9)	55
Pension and non-pension postretirement benefit contributions	(55)	(66)
Other assets and liabilities	(24)	(75)
Net cash flows provided by operating activities	279	194
Cash flows from investing activities		
Capital expenditures	(258)	(320)
Other investing activities	—	(3)
Net cash flows used in investing activities	(258)	(323)
Cash flows from financing activities		
Changes in short-term borrowings	57	145
Repayments of short-term borrowings with maturities greater than 90 days	—	(500)
Issuance of long-term debt	—	1
Retirement of long-term debt	(12)	(24)
Distributions to member	(71)	(69)
Contributions from member	—	500
Change in Exelon intercompany money pool	13	13
Net cash flows (used in) provided by financing activities	(13)	66
Increase (Decrease) in cash, cash equivalents and restricted cash	8	(63)
Cash, cash equivalents and restricted cash at beginning of period	95	236
Cash, cash equivalents and restricted cash at end of period	$103	$173

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 43	$ 30
Restricted cash and cash equivalents	40	42
Accounts receivable, net		
Customer	484	486
Other	210	206
Inventories, net		
Gas held in storage	2	7
Materials and supplies	152	151
Regulatory assets	507	554
Other	55	75
Total current assets	1,493	1,551
Property, plant and equipment, net	12,688	12,498
Deferred debits and other assets		
Regulatory assets	2,453	2,493
Investments	132	132
Goodwill	4,005	4,005
Long-term note receivable	4	4
Prepaid pension asset	527	490
Deferred income taxes	4	4
Other	69	70
Total deferred debits and other assets	7,194	7,198
Total assets[a]	$ 21,375	$ 21,247

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

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 407	$ 350
Long-term debt due within one year	385	396
Accounts payable	469	348
Accrued expenses	246	261
Payables to affiliates	100	90
Borrowings from Exelon intercompany money pool	13	—
Unamortized energy contract liabilities	162	188
Customer deposits	114	119
Merger related obligation	42	42
Regulatory liabilities	77	56
Other	52	81
Total current liabilities	2,067	1,931
Long-term debt	5,464	5,478
Deferred credits and other liabilities		
Regulatory liabilities	1,888	1,872
Deferred income taxes and unamortized investment tax credits	2,103	2,070
Asset retirement obligations	16	16
Non-pension postretirement benefit obligations	102	105
Unamortized energy contract liabilities	539	561
Other	377	389
Total deferred credits and other liabilities	5,025	5,013
Total liabilities[(a)]	12,556	12,422
Commitments and contingencies		
Member's equity		
Membership interest	8,835	8,835
Undistributed earnings (losses)	(16)	(10)
Total member's equity	8,819	8,825
Total liabilities and member's equity	$ 21,375	$ 21,247

(a) PHI’s consolidated total assets include $39 million and $41 million at March 31, 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 $95 million and $102 million at March 31, 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.

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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	—	65	65
Distribution to member	—	(71)	(71)
Balance, March 31, 2018	$ 8,835	$ (16)	$ 8,819

See the Combined Notes to Consolidated Financial Statements
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POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$536	$514
Revenues from alternative revenue programs	19	15
Operating revenues from affiliates	2	1
Total operating revenues	557	530
Operating expenses		
Purchased power	130	83
Purchased power from affiliates	52	83
Operating and maintenance	73	101
Operating and maintenance from affiliates	57	12
Depreciation and amortization	96	82
Taxes other than income	93	90
Total operating expenses	501	451
Operating income	56	79
Other income and (deductions)		
Interest expense, net	(31)	(29)
Other, net	8	8
Total other income and (deductions)	(23)	(21)
Income before income taxes	33	58
Income taxes	2	—
Net income	$31	$58
Comprehensive income	$31	$58

See the Combined Notes to Consolidated Financial Statements

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POTOMAC ELECTRIC POWER COMPANY
STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Three Months Ended March 31, 2018	2017
Cash flows from operating activities		
Net income	$31	$58
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	96	82
Deferred income taxes and amortization of investment tax credits	4	5
Other non-cash operating activities	10	(15)
Changes in assets and liabilities:		
Accounts receivable	—	45
Receivables from and payables to affiliates, net	(18)	(6)
Inventories	(2)	(10)
Accounts payable and accrued expenses	36	(49)
Income taxes	(3)	20
Pension and non-pension postretirement benefit contributions	(7)	(64)
Other assets and liabilities	(21)	(37)
Net cash flows provided by operating activities	126	29
Cash flows from investing activities		
Capital expenditures	(127)	(139)
Other investing activities	—	(5)
Net cash flows used in investing activities	(127)	(144)
Cash flows from financing activities		
Changes in short-term borrowings	34	144
Issuance of long-term debt	—	1
Dividends paid on common stock	(25)	(30)
Other financing activities	—	(1)
Net cash flows provided by financing activities	9	114
Increase (decrease) in cash, cash equivalents and restricted cash	8	(1)
Cash, cash equivalents and restricted cash at beginning of period	40	42
Cash, cash equivalents and restricted cash at end of period	$48	$41

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POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 15	$ 5
Restricted cash and cash equivalents	33	35
Accounts receivable, net		
Customer	246	250
Other	87	87
Inventories, net	89	87
Regulatory assets	207	213
Other	19	33
Total current assets	696	710
Property, plant and equipment, net	6,095	6,001
Deferred debits and other assets		
Regulatory assets	656	678
Investments	104	102
Prepaid pension asset	323	322
Other	22	19
Total deferred debits and other assets	1,105	1,121
Total assets	$ 7,896	$ 7,832

See the Combined Notes to Consolidated Financial Statements

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POTOMAC ELECTRIC POWER COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 60	$ 26
Long-term debt due within one year	19	19
Accounts payable	181	139
Accrued expenses	145	137
Payables to affiliates	56	74
Customer deposits	52	54
Regulatory liabilities	7	3
Merger related obligation	42	42
Current portion of DC PLUG obligation	30	28
Other	8	28
Total current liabilities	600	550
Long-term debt	2,521	2,521
Deferred credits and other liabilities		
Regulatory liabilities	838	829
Deferred income taxes and unamortized investment tax credits	1,076	1,063
Non-pension postretirement benefit obligations	34	36
Other	288	300
Total deferred credits and other liabilities	2,236	2,228
Total liabilities	5,357	5,299
Commitments and contingencies		
Shareholder's equity		
Common stock	1,470	1,470
Retained earnings	1,069	1,063
Total shareholder's equity	2,539	2,533
Total liabilities and shareholder's equity	$ 7,896	$ 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	—	31	31
Common stock dividends	—	(25)	(25)
Balance, March 31, 2018	$ 1,470	$ 1,069	$ 2,539

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$303	$285
Natural gas operating revenues	78	66
Revenues from alternative revenue programs	1	9
Operating revenues from affiliates	2	2
Total operating revenues	384	362
Operating expenses		
Purchased power	90	77
Purchased fuel	41	29
Purchased power from affiliate	46	51
Operating and maintenance	57	66
Operating and maintenance from affiliates	41	7
Depreciation and amortization	45	39
Taxes other than income	15	15
Total operating expenses	335	284
Operating income	49	78
Other income and (deductions)		
Interest expense, net	(13)	(13)
Other, net	2	3
Total other income and (deductions)	(11)	(10)
Income before income taxes	38	68
Income taxes	7	11
Net income	$31	$57
Comprehensive income	$31	$57

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Three Months Ended March 31, 2018	2017
Cash flows from operating activities		
Net income	$31	$57
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	45	39
Deferred income taxes and amortization of investment tax credits	10	13
Other non-cash operating activities	19	(7)
Changes in assets and liabilities:		
Accounts receivable	(1)	6
Receivables from and payables to affiliates, net	(16)	1
Inventories	7	1
Accounts payable and accrued expenses	18	14
Income Taxes	(5)	21
Other assets and liabilities	7	(23)
Net cash flows provided by operating activities	115	122
Cash flows from investing activities		
Capital expenditures	(65)	(82)
Other investing activities	—	2
Net cash flows used in investing activities	(65)	(80)
Cash flows from financing activities		
Changes in short-term borrowings	(5)	—
Retirement of long-term debt	(4)	(14)
Dividends paid on common stock	(36)	(30)
Net cash flows used in financing activities	(45)	(44)
Increase (Decrease) in cash, cash equivalents and restricted cash	5	(2)
Cash, cash equivalents and restricted cash at beginning of period	2	46
Cash, cash equivalents and restricted cash at end of period	$7	$44

See the Combined Notes to Consolidated Financial Statements

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 7	$ 2
Accounts receivable, net		
Customer	141	146
Other	43	38
Receivables from affiliates	2	—
Inventories, net		
Gas held in storage	2	7
Materials and supplies	34	36
Regulatory assets	63	69
Other	22	27
Total current assets	314	325
Property, plant and equipment, net	3,620	3,579
Deferred debits and other assets		
Regulatory assets	242	245
Goodwill	8	8
Prepaid pension asset	192	193
Other	7	7
Total deferred debits and other assets	449	453
Total assets	$ 4,383	$ 4,357

See the Combined Notes to Consolidated Financial Statements

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DELMARVA POWER & LIGHT COMPANY
BALANCE SHEETS
(Unaudited)

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 211	$ 216
Long-term debt due within one year	79	83
Accounts payable	106	82
Accrued expenses	43	35
Payables to affiliates	32	46
Customer deposits	34	35
Regulatory liabilities	48	42
Other	5	8
Total current liabilities	558	547
Long-term debt	1,217	1,217
Deferred credits and other liabilities		
Regulatory liabilities	598	593
Deferred income taxes and unamortized investment tax credits	618	603
Non-pension postretirement benefit obligations	13	14
Other	49	48
Total deferred credits and other liabilities	1,278	1,258
Total liabilities	3,053	3,022
Commitments and contingencies		
Shareholder's equity		
Common stock	764	764
Retained earnings	566	571
Total shareholder's equity	1,330	1,335
Total liabilities and shareholder's equity	$ 4,383	$ 4,357

See the Combined Notes to Consolidated Financial Statements

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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	—	31	31
Common stock dividends	—	(36)	(36)
Balance, March 31, 2018	$ 764	$ 566	$ 1,330

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Operating revenues		
Electric operating revenues	$311	$268
Revenues from alternative revenue programs	(2)	6
Operating revenues from affiliates	1	1
Total operating revenues	310	275
Operating expenses		
Purchased power	155	128
Purchased power from affiliates	6	9
Operating and maintenance	54	69
Operating and maintenance from affiliates	36	7
Depreciation and amortization	33	35
Taxes other than income	3	2
Total operating expenses	287	250
Operating income	23	25
Other income and (deductions)		
Interest expense, net	(16)	(15)
Other, net	1	2
Total other income and (deductions)	(15)	(13)
Income before income taxes	8	12
Income taxes	1	(16)
Net income	$7	$28
Comprehensive income	$7	$28

See the Combined Notes to Consolidated Financial Statements

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

	Three Months Ended March 31,	
(In millions)	2018	2017
Cash flows from operating activities		
Net income	$7	$28
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	33	35
Deferred income taxes and amortization of investment tax credits	2	(7)
Other non-cash operating activities	9	2
Changes in assets and liabilities:		
Accounts receivable	(5)	14
Receivables from and payables to affiliates, net	(4)	(5)
Inventories	—	(1)
Accounts payable and accrued expenses	30	(5)
Income taxes	—	3
Pension and non-pension postretirement benefit contributions	(6)	—
Other assets and liabilities	(7)	(6)
Net cash flows provided by operating activities	59	58
Cash flows from investing activities		
Capital expenditures	(63)	(88)
Other investing activities	(1)	1
Net cash flows used in investing activities	(64)	(87)
Cash flows from financing activities		
Changes in short-term borrowings	28	—
Retirement of long-term debt	(8)	(10)
Dividends paid on common stock	(9)	(10)
Net cash flows provided by (used in) financing activities	11	(20)
Increase (Decrease) in cash, cash equivalents and restricted cash	6	(49)
Cash, cash equivalents and restricted cash at beginning of period	31	133
Cash, cash equivalents and restricted cash at end of period	$37	$84

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

(In millions)	March 31, 2018	December 31, 2017
ASSETS		
Current assets		
Cash and cash equivalents	$ 10	$ 2
Restricted cash and cash equivalents	7	6
Accounts receivable, net		
Customer	97	92
Other	51	56
Receivables from affiliates	1	—
Inventories, net	29	29
Regulatory assets	64	71
Other	4	2
Total current assets	263	258
Property, plant and equipment, net	2,767	2,706
Deferred debits and other assets		
Regulatory assets	377	359
Long-term note receivable	4	4
Prepaid pension asset	76	73
Other	43	45
Total deferred debits and other assets	500	481
Total assets[(a)]	$ 3,530	$ 3,445

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	March 31, 2018	December 31, 2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$ 136	$ 108
Long-term debt due within one year	278	281
Accounts payable	166	118
Accrued expenses	41	33
Payables to affiliates	26	29
Customer deposits	28	31
Regulatory liabilities	21	11
Other	7	8
Total current liabilities	703	619
Long-term debt	836	840
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	496	493
Non-pension postretirement benefit obligations	14	14
Regulatory liabilities	416	411
Other	24	25
Total deferred credits and other liabilities	950	943
Total liabilities[(a)]	2,489	2,402
Commitments and contingencies		
Shareholder's equity		
Common stock	912	912
Retained earnings	129	131
Total shareholder's equity	1,041	1,043
Total liabilities and shareholder's equity	$ 3,530	$ 3,445

(a) ACE’s consolidated total assets include $27 million and $29 million at March 31, 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 $83 million and $90 million at March 31, 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.

See the Combined Notes to Consolidated Financial Statements

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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	—	7	7
Common stock dividends	—	(9)	(9)
Balance, March 31, 2018	$ 912	$ 129	$ 1,041

See the Combined Notes to Consolidated Financial Statements

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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)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey

Transmission and distribution of electricity to retail customers

Basis of Presentation (All Registrants)

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 March 31, 2018 and 2017 and for the three 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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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Prior Period Adjustments and Reclassifications (All Registrants)

In the second quarter of 2017, errors were identified related to the Exelon, Generation, ComEd, PECO and BGE Consolidated Statements of Cash Flows for the three months ended March 31, 2017. These classification errors related to the presentation of changes in Accounts payable and accrued expenses and Accounts receivable within Cash flows provided by operating activities and Capital expenditures and Proceeds from sale of long-lived assets within Cash flows used in investing activities. These errors have been corrected in Exelon's, Generation's, ComEd's, PECO's, and BGE's Consolidated Statements of Cash Flows for the three months ended March 31, 2017 that are presented in this first quarter 2018 Form 10-Q. As revised, the Cash flows provided by operating activities for the three months ended March 31, 2017 are $1,074 million, $420 million, $236 million, $106 million and $208 million for Exelon, Generation, ComEd, PECO and BGE, respectively, an increase (decrease) of $(127) million, $(320) million, $91 million, $42 million and $40 million for Exelon, Generation, ComEd, PECO and BGE, respectively, from the originally reported amounts. As revised, the Cash flows used in investing activities are $2,283 million, $910 million, $619 million, $69 million and $202 million for Exelon, Generation, ComEd, PECO and BGE, respectively, an increase (decrease) of $(127) million, $(320) million, $91 million, $42 million and $40 million for Exelon, Generation, ComEd, PECO and BGE, respectively, from the originally reported amounts. Management concluded that the errors are not material to the previously issued financial statements.

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 further 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 further 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 further 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 further information.

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

Three Months Ended March 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating Revenues - As reported									
Competitive business revenues	$4,560	$ —	$—	$ —	$—	$—	$—	$—	$—
Rate-regulated utility revenues	4,197	—	—	—	—	—	—	—	—
Operating revenues	—	4,558	—	—	—	—	—	—	—
Electric operating revenues	—	—	1,293	589	665	1,097	529	294	274
Natural gas operating revenues	—	—	—	206	281	66	—	66	—
Operating revenues from affiliates	—	330	5	1	5	12	1	2	1
Total operating revenues	$8,757	$ 4,888	$1,298	$ 796	$951	$1,175	$530	$362	$275
Operating Revenues - Adjustments									
Competitive business revenues	$(10)	$ —	$—	$ —	$—	$—	$—	$—	$—
Rate-regulated utility revenues	(79)	—	—	—	—	—	—	—	—
Operating revenues	—	(10)	—	—	—	—	—	—	—
Electric operating revenues	—	—	(14)	—	(25)	(30)	(15)	(9)	(6)
Natural gas operating revenues	—	—	—	—	(10)	—	—	—	—
Revenues from alternative revenue programs	79	—	14	—	35	30	15	9	6
Operating revenues from affiliates	—	—	—	—	—	—	—	—	—
Total operating revenues	$(10)	$ (10)	$—	$ —	$—	$—	$—	$—	$—
Operating Revenues - Retrospective application									
Competitive business revenues	$4,550	$ —	$—	$ —	$—	$—	$—	$—	$—
Rate-regulated utility revenues	4,118	—	—	—	—	—	—	—	—
Operating revenues	—	4,548	—	—	—	—	—	—	—
Electric operating revenues	—	—	1,279	589	640	1,067	514	285	268
Natural gas operating revenues	—	—	—	206	271	66	—	66	—
Revenues from alternative revenue programs	79	—	14	—	35	30	15	9	6
Operating revenues from affiliates	—	330	5	1	5	12	1	2	1
Total operating revenues	$8,747	$ 4,878	$1,298	$ 796	$951	$1,175	$530	$362	$275

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 further 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. Refer to Note 6 — Regulatory Matters and Note 10 — Derivative Financial Instruments for further 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.

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, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE.

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 March 31, 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 March 31, 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 January 2018, the FASB proposed amending the standard to give entities another option for transition. The proposed transition method would allow entities to initially apply the requirements of the standard in the period of adoption (January 1, 2019). The Registrants will assess this transition option when the FASB issues the standard.

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 reassess initial direct costs associated with existing leases. The Registrants expect to 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 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 which includes completing a detailed contract assessment for a sample of transactions to determine whether they are leases under the new guidance.
- 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.

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 March 31, 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 guidance is effective January 1, 2019 and early adoption is permitted with a modified retrospective transition approach. The Registrants are currently assessing this standard but do not currently expect a significant impact given the limited activity for which the Registrants elect hedge accounting and because the Registrants do not anticipate increasing their use of hedge accounting as a result of this standard.

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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 March 31, 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 March 31, 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 March 31, 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
- certain retail power and gas companies for which Generation is the sole supplier of energy, and
- CENG.

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

As of March 31, 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 $30 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 (see Note 26 — Related Party Transactions of the Exelon 2017 Form 10-K for additional information regarding Generation's and Exelon's transactions with 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 Reliability Support Services Agreement (RSSA), through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017 (see Note 6 — Regulatory Matters for additional details),
- Generation provided a $400 million loan to CENG. As of March 31, 2018, the remaining obligation is $337 million, including accrued interest, which reflects the principal payment made in January 2015,
- 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 more details),
- 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.

As of March 31, 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 months ended March 31, 2018, ACE transferred $8 million to ATF. During the three months ended March 31, 2017, ACE transferred $19 million to ATF.

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

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

- 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 March 31, 2018 and December 31, 2017 are as follows:

	March 31, 2018				December 31, 2017			
	Exelon[(a)]	Generation	PHI[(a)]	ACE	Exelon[(a)]	Generation	PHI[(a)]	ACE
Current assets	$823	$ 812	$ 11	$ 7	$662	$ 652	$ 10	$ 6
Noncurrent assets	9,279	9,251	28	20	9,317	9,286	31	23
Total assets	$10,102	$ 10,063	$ 39	$ 27	$9,979	$ 9,938	$ 41	$ 29
Current liabilities	$269	$ 236	$ 33	$ 29	$308	$ 272	$ 36	$ 32
Noncurrent liabilities	3,292	3,230	62	54	3,316	3,250	66	58
Total liabilities	$3,561	$ 3,466	$ 95	$ 83	$3,624	$ 3,522	$ 102	$ 90

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

(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 March 31, 2018 and December 31, 2017, these assets and liabilities primarily consisted of the following:

	March 31, 2018				December 31, 2017			
	Exelon (a)	Generation	PHI (a)	ACE	Exelon (a)	Generation	PHI (a)	ACE
Cash and cash equivalents	$280	$ 280	$—	$ —	$126	$ 126	$ —	$ —
Restricted cash	73	66	7	7	64	58	6	6
Accounts receivable, net								
Customer	154	154	—	—	170	170	—	—
Other	29	29	—	—	25	25	—	—
Inventory								
Materials and supplies	202	202	—	—	205	205	—	—
Other current assets	55	51	4	—	45	41	4	—
Total current assets	793	782	11	7	635	625	10	6
Property, plant and equipment, net	6,181	6,181	—	—	6,186	6,186	—	—
Nuclear decommissioning trust funds	2,483	2,483	—	—	2,502	2,502	—	—
Other noncurrent assets	270	242	28	20	274	243	31	23
Total noncurrent assets	8,934	8,906	28	20	8,962	8,931	31	23
Total assets	$9,727	$ 9,688	$39	$ 27	$9,597	$ 9,556	$ 41	$ 29
Long-term debt due within one year	$102	$ 70	$32	$ 28	$102	$ 67	$ 35	$ 31
Accounts payable	93	93	—	—	114	114	—	—
Accrued expenses	52	51	1	1	67	66	1	1
Unamortized energy contract liabilities	17	17	—	—	18	18	—	—
Other current liabilities	5	5	—	—	7	7	—	—
Total current liabilities	269	236	33	29	308	272	36	32
Long-term debt	1,125	1,063	62	54	1,154	1,088	66	58
Asset retirement obligations	2,062	2,062	—	—	2,035	2,035	—	—
Unamortized energy contract liabilities	1	1	—	—	5	5	—	—
Other noncurrent liabilities	99	99	—	—	116	116	—	—
Total noncurrent liabilities	3,287	3,225	62	54	3,310	3,244	66	58
Total liabilities	$3,556	$ 3,461	$95	$ 83	$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 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

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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 March 31, 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 March 31, 2018 and December 31, 2017, ComEd, PECO, BGE, PHI, Pepco, ACE and DPL did not have any material unconsolidated VIEs.

As of March 31, 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 $9 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 $9 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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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

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

March 31, 2018	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 626	$ 501	$ 1,127
Total liabilities[(a)]	37	225	262
Exelon's ownership interest in VIE[(a)]	—	246	246
Other ownership interests in VIE[(a)]	588	30	618
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments	—	246	246
Contract intangible asset	8	—	8
Net assets pledged for Zion Station decommissioning[(b)]	2	—	2

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

(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 $30 million and $39 million as of March 31, 2018 and December 31, 2017, respectively; offset by payables to ZionSolutions, LLC of $28 million and $37 million as of March 31, 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 — Nuclear Decommissioning for additional details.

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.

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

Acquisition of Handley Generating Station (Exelon and Generation)

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 (Exelon and Generation)

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 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 — Nuclear Decommissioning and Note 14 — Retirement Benefits for additional information regarding the FitzPatrick decommissioning ARO and pension and OPEB updates.

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

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

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(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 background regarding SNF obligations to the DOE.

Exelon and Generation incurred $32 million of merger and integration costs related to FitzPatrick for the three months ended March 31, 2017, 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 months ended March 31, 2018.

Asset Dispositions

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 Generations' 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 in Gain on sales of assets and businesses on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2018.

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 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. Revenues related to such contracts are generally recognized over time as the power is generated and simultaneously delivered to the customer. However, revenues related to the sale of any goods or services that are not simultaneously received and consumed by the customer are recognized as the performance obligations are satisfied at a point in time. 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, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

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 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, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

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 $25 million and $26 million as of March 31, 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 $5 million and $9 million for the three months ended March 31, 2018 and 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

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

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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 - 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 March 31, 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	28
Amounts reclassified to receivables	(9)
Balance at March 31, 2018	$ 302

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 March 31, 2018:

Contract Liabilities	Exelon and Generation
Balance as of January 1, 2018	$ 35
Increases as a result of additional cash received or due	227
Amounts recognized into revenues	(216)
Balance at March 31, 2018	$ 46

The Utility Registrants also record contract liabilities when consideration is received prior to the satisfaction of the performance obligations. As of March 31, 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 March 31, 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.

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

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.

	2019	2020	2021	2022	2023 and thereafter	Total
Exelon	$544	$264	$104	$46	$ 128	$1,086
Generation	544	264	104	46	128	$1,086

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. Refer to Note 12 — Income Taxes for more detail 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 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. The annual reconciliation for 2017 provided 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. For additional information on ComEd's distribution formula rate filings see Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K.

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 services costs regulatory asset in the first quarter 2017.

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. In the first quarter of 2018, Generation recognized approximately $202 million of revenue, 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 argue that the Illinois ZEC program will distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices, and seek a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits. In addition, on March 31, 2017, plaintiffs in both lawsuits filed motions for preliminary injunction with the court; the court stayed briefing on the motions for preliminary injunction until the resolution of the motions to dismiss. On July 14, 2017, the district court granted the motions to dismiss. On July 17, 2017, the plaintiffs appealed the decision to the Seventh Circuit. Briefs were fully submitted on December 12, 2017, the Court heard oral argument on January 3, 2018. At the argument, the Court asked for supplemental briefing, which was filed on January 26, 2018. On February 21, 2018, the Seventh Circuit issued an order inviting the Solicitor General to express the views of the United States on the matter, however the timing of that response is currently uncertain. Exelon cannot predict the outcome of these lawsuits. It is possible that resolution of these matters could have a material, unfavorable impact on Exelon’s and Generation’s results of operations, cash flows, and financial positions.

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 is 10.95%. PECO expects a decision on its electric distribution rate case proceeding in the fourth quarter of 2018 but cannot predict what increase, if any, the PAPUC will approve.

Tax Cuts and Jobs Act (Exelon and PECO). 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, which would be an additional offset to the proposed increase to its electric distribution rates. PECO will file with the PAPUC in 2018 seeking approval to pass back to gas distribution customers $4 million in TCJA tax savings beginning January 1, 2019. The amounts being proposed to be passed back to customers reflect the annual benefit of lower income tax rates established upon enactment of the TCJA. PECO cannot predict the amount or timing of the refunds the PAPUC will ultimately approve. See Note 12 — Income Taxes for more detail 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. It is expected that the MDPSC will address later in 2018 the treatment of BGE's TCJA tax savings for the period January 1, 2018 through February 1, 2018.

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. See discussion below for further details.

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 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 more detail 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.

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%. The parties to the settlement agreement have requested that Pepco’s new rates be effective on June 1, 2018. 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. Pepco expects a decision in the matter in the second quarter of 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.

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 more details.

2017 Delaware Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). On August 17, 2017, DPL filed applications with the DPSC to increase its annual electric and natural gas distribution base rates by $24 million and $13 million, respectively, reflecting a requested ROE of 10.1%. DPL filed updated testimony on October 18, 2017, to request a $31 million increase in electric distribution base rates, and updated testimony on November 7, 2017, to request an $11 million increase in natural gas distribution base rates. On October 16, 2017 and November 1, 2017, $2.5 million of the proposed rate increases for electric and natural gas, respectively, were put into effect, subject to refund, based on the final DPSC order. On February 9, 2018, DPL filed with the DPSC updates to its distribution base rate cases to reflect $26 million in ongoing annual TCJA tax savings, of which $19 million and $7 million is related to electric and natural gas, respectively. The proposed distribution base rate increase in each rate case were lowered by those amounts, which 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. It is expected that the DPSC will address in a future rate proceeding DPL's treatment of the TCJA tax savings for the period February 1, 2018 through the effective date of any final customer rate adjustments in the pending rate proceedings. On March 17, 2018, an additional $3 million of the proposed rate increase in the electric distribution base rate case and $1 million in the natural gas distribution base rate case was put into effect subject to refund based on the final DPSC order. DPL expects decisions on its electric and natural gas distribution base rate proceedings in the third and fourth quarters of 2018, respectively, but cannot predict how much of the requested increases the DPSC will approve.

See Note 12 — Income Taxes for more detail 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. See discussion below for more details.

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 a ROE of 9.525%. The parties to the settlement agreement have requested that Pepco’s new rates be effective on July 1, 2018. In addition, the settlement agreement separately provides 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. Pepco expects a decision in the matter in the second quarter of 2018.

See Note 12 — Income Taxes for more detail 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 effective April 1, 2018 and July 1, 2018. 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. 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, with the proposed final electric distribution base rates, representing the full $23 million decrease to be effective on July 1, 2018. It is expected that the NJBPU will address in a future rate proceeding ACE's treatment of the TCJA tax savings for the period January 1, 2018 through the effective date of any final customer rate adjustments. See Note 12 — Income Taxes for more detail 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.

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 through a new rider mechanism a series of investments, 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. An NJBPU decision has been requested by the fourth quarter of 2018.

Update and Reconciliation of Certain 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. The net impact of adjusting the charges as proposed is an overall annual rate decrease of approximately $19 million, including New Jersey sales and use tax. The matter is pending at the NJBPU. ACE has requested that the NJBPU place the new rates into effect by June 1, 2018. An NJBPU decision has been requested by the fourth quarter of 2018.

New York Regulatory Matters

New York Clean Energy Standard (Exelon and Generation). On August 1, 2016, the New York Public Service Commission (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, plaintiffs appealed the decision to the Second Circuit. Plaintiffs-Appellants' initial brief was filed on October 13, 2017. Briefing in the appeal was completed in December 2017 and oral argument was held on March 12, 2018.

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 are due on May 11, 2018.

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

Federal Regulatory Matters

Tax Cuts and Jobs Act and Transmission-Related Income Tax Regulatory Assets (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). Pursuant to their respective transmission formula rates, ComEd, BGE, Pepco, DPL and ACE will begin 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. 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. 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.

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.

ComEd, Pepco, DPL and ACE have similar transmission-related income tax regulatory liabilities and assets also requiring FERC approval separate from their transmission formula rate mechanisms. On February 23, 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. The companies requested the revisions be effective as of April 24, 2018. On April 24, 2018, the FERC issued a letter order neither approving or rejecting the filings, but rather indicating that the filings were deficient and requiring the parties to file additional information within 30 days. 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. As discussed below, PECO is currently in settlement discussions regarding its transmission formula rate and expects to pass back TCJA benefits to customers through its annual formula rate update.

Each of BGE, ComEd, Pepco, DPL and ACE believe there is sufficient basis to support full recovery of their existing transmission-related income tax regulatory assets, as evidenced by the further pursuit of full recovery with FERC. However, upon further consideration of the November 16, 2017 FERC 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 2017, reducing their associated transmission-related income tax regulatory assets.

If any of the companies are ultimately successful with FERC allowing future recovery of these amounts, the associated regulatory assets will be reestablished, with corresponding decreases to Income tax expense. To the extent all or a portion of the prospective amortization amounts were no longer considered probable of recovery, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately \$82 million, \$41 million, \$22 million, \$19 million, \$9 million, \$7 million and \$3 million, respectively, as of March 31, 2018.

The Utility Registrants cannot predict the outcome of these FERC proceedings.

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 would 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. PECO cannot predict the final outcome of the settlement or hearing proceedings, or the transmission formula FERC may approve.

DOE Notice of Proposed Rulemaking (Exelon and Generation). 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. The DOE's NOPR recommended that the FERC take comments for 45 days after publication in the Federal Register and issue a final order 60 days after such publication. On January 8, 2018, the FERC issued an order terminating the rulemaking docket that was 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, the 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. The FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Interested parties may submit reply comments through May 9, 2018. 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.

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, Exelon and the US Fish and Wildlife Service of the US 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 46-year life of the new license, including both capital and operating costs. The actual timing and

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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, MDE issued its 401 certification for Conowingo. As issued, the 401 certification imposes requirements and conditions 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. Generation is reviewing the certification and will determine next steps to ensure the long-term viability of the Conowingo Dam.

As of March 31, 2018, $32 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.

Regulatory Assets and Liabilities (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE 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, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of March 31, 2018 and December 31, 2017. For additional information on the specific regulatory assets and liabilities, refer to Note 3 — Regulatory Matters of the Exelon 2017 Form 10-K.

March 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits[(a)]	$3,844	$—	$—	$—	$—	$—	$—	$—
Deferred income taxes	336	—	327	—	9	9	—	—
AMI programs[(c)]	621	151	33	208	229	154	75	—
Electric distribution formula rate[(d)]	256	256	—	—	—	—	—	—
Energy efficiency costs	220	220	—	—	—	—	—	—
Debt costs	108	36	1	11	71	15	7	5
Fair value of long-term debt	745	—	—	—	607	—	—	—
Fair value of PHI's unamortized energy contracts	701	—	—	—	701	—	—	—
Asset retirement obligations	111	75	22	14	—	—	—	—
MGP remediation costs	284	263	21	—	—	—	—	—
Under-recovered uncollectible accounts	69	69	—	—	—	—	—	—
Renewable energy	268	267	—	—	1	—	—	1
Energy and transmission programs[(e)(f)(g)(h)(i)(j)]	117	8	43	21	45	7	14	24
Deferred storm costs	46	—	—	—	46	12	5	29
Energy efficiency and demand response programs	559	—	1	269	289	212	77	—
Merger integration costs[(k)(l)(m)]	46	—	—	5	41	20	11	10
Under-recovered revenue decoupling[(n)]	44	—	—	6	38	38	—	—
COPCO acquisition adjustment	5	—	—	—	5	—	5	—
Workers compensation and long-term disability costs	33	—	—	—	33	33	—	—
Vacation accrual	27	—	14	—	13	—	8	5
Securitized stranded costs	71	—	—	—	71	—	—	71
CAP arrearage	12	—	12	—	—	—	—	—
Removal costs	535	—	—	—	535	150	94	292
DC PLUG charge	187	—	—	—	187	187	—	—
Other	63	6	12	6	39	26	9	4
Total regulatory assets	9,308	1,351	486	540	2,960	863	305	441
Less: current portion	1,245	226	78	149	507	207	63	64
Total noncurrent regulatory assets	$8,063	$1,125	$408	$391	$2,453	$656	$242	$377

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March 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$26	$—	$ —	$—	$—	$ —	$—	$—
Deferred income taxes[b]	5,189	2,458	—	1,011	1,720	804	506	410
Nuclear decommissioning	2,969	2,464	505	—	—	—	—	—
Removal costs	1,570	1,348	—	92	130	20	110	—
Deferred rent	35	—	—	—	35	—	—	—
Energy efficiency and demand response programs	16	4	11	—	1	—	—	1
DLC program costs	7	—	7	—	—	—	—	—
Electric distribution tax repairs	27	—	27	—	—	—	—	—
Gas distribution tax repairs	8	—	8	—	—	—	—	—
Energy and transmission programs[e][f][g][h][i][j]	153	53	56	22	22	4	6	12
Over-recovered revenue decoupling[n]	14	—	—	11	3	—	3	—
Renewable portfolio standards costs	81	81	—	—	—	—	—	—
Zero emission credit costs	8	8	—	—	—	—	—	—
Over-recovered uncollectible accounts	4	—	—	—	4	—	—	4
Merger integration costs[l]	1	—	—	—	1	—	1	—
TCJA income tax benefit over-recoveries[o]	54	—	10	17	27	14	7	6
Other	84	8	22	32	22	3	13	4
Total regulatory liabilities	10,246	6,424	646	1,185	1,965	845	646	437
Less: current portion	522	212	117	102	77	7	48	21
Total noncurrent regulatory liabilities	$9,724	$6,212	$ 529	$1,083	$1,888	$ 838	$598	$416

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 regulatory assets established at the Constellation and PHI merger dates of $427 million and $934 million, respectively, as of March 31, 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 March 31, 2018, includes transmission-related income tax regulatory liabilities that require FERC approval separate from the transmission formula rate of $479 million, $135 million, $146 million, $147 million and $147 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 March 31, 2018, BGE's regulatory asset of $208 million includes $125 million of unamortized incremental deployment costs under the program, $51 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. 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 March 31, 2018, ComEd's regulatory asset of $256 million was comprised of $195 million for the 2016, 2017 and 2018 annual reconciliations and $61 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 March 31, 2018, ComEd's regulatory asset of $8 million represents transmission costs recoverable through its FERC approved formula rate. As of March 31, 2018, ComEd's regulatory liability of $53 million included $21 million related to over-recovered energy costs and $32 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 March 31, 2018, PECO's regulatory liability of $56 million included $44 million related to over-recovered costs under the DSP program, $3 million related to the over-recovered transmission service charges and $9 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 March 31, 2018, BGE's regulatory asset of $21 million included $13 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $5 million related to under-recovered electric energy costs and $3 million of abandonment costs to be recovered upon FERC approval. As of March 31, 2018, BGE's regulatory liability of $22 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 March 31, 2018, Pepco's regulatory asset of $7 million included $4 million of transmission costs recoverable through its FERC approved formula rate and $3 million related to under-recovered electric energy costs. As of March 31, 2018, Pepco's regulatory liability of $4 million related to over-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 March 31, 2018, DPL's regulatory asset of $14 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $3 million related to under-recovered electric energy costs. As of March 31, 2018, DPL's regulatory liability of $6 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 March 31, 2018, ACE's regulatory asset of $24 million included $9 million of transmission costs recoverable through its FERC approved formula rate and $15 million of under-recovered electric energy costs. As of March 31, 2018, ACE's regulatory liability of $12 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 March 31, 2018 and 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.

(l) As of March 31, 2018, DPL’s regulatory asset of $11 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 $2 million authorized for recovery in Delaware gas rates. As of March 31, 2018, DPL’s regulatory liability of $1 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 March 31, 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.

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(n) Represents the electric and natural gas distribution costs recoverable from customers under BGE’s decoupling mechanism. As of March 31, 2018, BGE had a regulatory asset of $6 million related to under-recovered electric revenue decoupling and a regulatory liability of $11 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 further details on the regulatory proceedings.

Capitalized Ratemaking Amounts Not Recognized (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The following table illustrates our authorized amounts capitalized for ratemaking purposes related to earnings on shareholders’ investment that are not recognized for financial reporting purposes on our Consolidated Balance Sheets. These amounts will be recognized as revenues in our 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
March 31, 2018	$ 69	$ 7	$ —	$ 52	$ 10	$ 6	$ 4	$ —

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

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(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.

Purchase of Receivables Programs (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

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, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon’s, ComEd’s, PECO’s, BGE’s, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of March 31, 2018 and December 31, 2017.

As of March 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Purchased receivables	$ 317	$ 88	$ 73	$ 64	$ 92	$ 55	$ 17	$ 20
Allowance for uncollectible accounts[(a)]	(35)	(16)	(6)	(4)	(9)	(5)	(1)	(3)
Purchased receivables, net	$ 282	$ 72	$ 67	$ 60	$ 83	$ 50	$ 16	$ 17

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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)

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.

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 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. Refer to Note 6 — Regulatory Matters for additional discussion on the New York CES and the Illinois ZES.

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 Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

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On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle by October 2018. 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 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 — Nuclear Decommissioning for additional detail on changes to the nuclear decommissioning ARO balance.

Exelon's and Generation's first quarter 2018 results included a net incremental $178 million 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)	Q1 2018
Depreciation and amortization[(a)]	
Accelerated depreciation[(b)]	$ 137
Accelerated nuclear fuel amortization	15
Operating and maintenance[(c)]	26
Total	$ 178

(a) Reflects incremental accelerated depreciation and amortization for TMI for the quarter ended March 31, 2018, and for Oyster Creek from February 2, 2018 through March 31, 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.

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

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 April 12, 2018, a bill was passed by both Houses of the New Jersey legislature that would 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. The program provides transparency and includes robust customer protections. The New Jersey Governor has up to 45 days to sign the bill, with the bill becoming effective immediately upon signing. The NJBPU then 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. Exelon and Generation continue to work with stakeholders.

The following table provides the balance sheet amounts as of March 31, 2018 for Generation’s ownership share of the significant assets and liabilities associated with Salem.

	March 31, 2018
Asset Balances	
Materials and supplies inventory	$ 45
Nuclear fuel inventory, net	102
Completed plant, net	618
Construction work in progress	27
Liability Balances	
Asset retirement obligation	(446)
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

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end of the current capacity commitment for Mystic Units 7 & 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 planning year. The ISO-NE recently announced that it would take a three-step approach to fuel security. First, ISO-NE will make a filing soon to obtain tariff waivers to allow it to retain Mystic 8 and 9 for fuel security for the 2022 - 2024 planning years. Second, ISO-NE will 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 will 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 April 3, 2018, ISO-NE issued a memorandum to the NEPOOL Participants' Committee announcing its intention to seek FERC approval for waiver of certain tariff provisions in order to allow it to retain Mystic Units 8 and 9 for fuel security reasons. On April 4, 2018, Generation issued a letter indicating its willingness to cooperate and submit to full cost-of-service compensation for the Mystic Units 8 and 9, provided that the cost-of-service rate is determined before it commits to any future capacity obligation.

The following table provides the balance sheet amounts as of March 31, 2018 for Generation's significant assets and liabilities associated with the Mystic Generating Station assets.

	March 31, 2018
Asset Balances	
Materials and supplies inventory	$ 26
Fuel inventory	18
Completed plant, net	896
Construction work in progress	4
Prepaid expense[(a)]	9
Liability Balances	
Asset retirement obligation	(5)
Accrued expense[(a)]	(2)

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

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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 March 31, 2018 and December 31, 2017:

Exelon

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$1,654	$—	$1,654	$—	$1,654
Long-term debt (including amounts due within one year)[b][c]	34,108	—	33,091	1,893	34,984
Long-term debt to financing trusts[d]	389	—	—	421	421
SNF obligation	1,151	—	922	—	922

	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

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$166	$—	$166	$—	$166
Long-term debt (including amounts due within one year)[b][c]	8,965	—	7,585	1,610	9,195
SNF obligation	1,151	—	922	—	922

	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

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ComEd

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$317	$—	$317	$—	$317
Long-term debt (including amounts due within one year)[(b)(c)]	7,694	—	8,061	—	8,061
Long-term debt to financing trusts[(d)]	205	—	—	222	222

	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

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$220	$—	$220	$—	$220
Long-term debt (including amounts due within one year)[(b)(c)]	2,723	—	2,870	—	2,870
Long-term debt to financing trusts[(d)]	184	—	—	199	199

	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[(d)]	184	—	—	204	204

BGE

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[(a)]	$45	$—	$45	$—	$45
Long-term debt (including amounts due within one year)[(b)(c)]	$2,578	$—	$2,689	$—	$2,689

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	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

PHI

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$407	$—	$407	$ —	$407
Long-term debt (including amounts due within one year)[b][c]	5,849	—	5,423	283	5,706

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
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

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$60	$—	$ 60	$ —	$ 60
Long-term debt (including amounts due within one year)[b][c]	2,540	—	2,933	9	2,942

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
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

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$211	$—	$211	$ —	$211
Long-term debt (including amounts due within one year)[b][c]	1,296	—	1,320	—	1,320

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

ACE

	March 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities[a]	$136	$—	$136	$—	$136
Long-term debt (including amounts due within one year)[b][c]	1,114	—	916	274	1,190
	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

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(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 $213 million, $57 million, $60 million, $20 million, $16 million, $6 million, $32 million, $11 million and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of March 31, 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 and government-backed fixed rate non-recourse debt.

(d) Includes unamortized debt issuance costs which are not fair valued of $1 million and $1 million for Exelon and ComEd, respectively, as of March 31, 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

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were no material transfers between Level 1 and Level 2 during the three months ended March 31, 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.

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 March 31, 2018 and December 31, 2017:

	Generation					Exelon				
As of March 31, 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]	343	—	—	—	343	517	—	—	—	517
NDT fund investments										
Cash equivalents[b]	222	105	—	—	327	222	105	—	—	327
Equities	4,002	983	—	2,119	7,104	4,002	983	—	2,119	7,104
Fixed income										
Corporate debt	—	1,583	240	—	1,823	—	1,583	240	—	1,823
U.S. Treasury and agencies	1,869	88	—	—	1,957	1,869	88	—	—	1,957
Foreign governments	—	86	—	—	86	—	86	—	—	86
State and municipal debt	—	254	—	—	254	—	254	—	—	254
Other[c]	—	39	—	532	571	—	39	—	532	571
Fixed income subtotal	1,869	2,050	240	532	4,691	1,869	2,050	240	532	4,691
Middle market lending	—	—	369	127	496	—	—	369	127	496
Private equity	—	—	—	253	253	—	—	—	253	253
Real estate	—	—	—	488	488	—	—	—	488	488
NDT fund investments subtotal[d]	6,093	3,138	609	3,519	13,359	6,093	3,138	609	3,519	13,359
Pledged assets for Zion Station decommissioning										
Cash equivalents	13	—	—	—	13	13	—	—	—	13

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As of March 31, 2018	Generation					Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Middle market lending	—	—	16	—	16	—	—	16	—	16
Pledged assets for Zion Station decommissioning subtotal[e]	13	—	16	—	29	13	—	16	—	29
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	77	—	—	—	77
Mutual funds	24	—	—	—	24	59	—	—	—	59
Fixed income	—	—	—	—	—	—	10	—	—	10
Life insurance contracts	—	22	—	—	22	—	71	23	—	94
Rabbi trust investments subtotal[f]	29	22	—	—	51	136	81	23	—	240
Commodity derivative assets										
Economic hedges	286	2,923	1,892	—	5,101	286	2,923	1,892	—	5,101
Proprietary trading	—	151	58	—	209	—	151	58	—	209
Effect of netting and allocation of collateral[g] [h]	(335)	(2,589)	(895)	—	(3,819)	(335)	(2,589)	(895)	—	(3,819)
Commodity derivative assets subtotal	(49)	485	1,055	—	1,491	(49)	485	1,055	—	1,491
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	12	—	—	12	—	12	—	—	12
Economic hedges	—	6	—	—	6	—	6	—	—	6
Effect of netting and allocation of collateral	(1)	(3)	—	—	(4)	(1)	(3)	—	—	(4)
Interest rate and foreign currency derivative assets subtotal	(1)	15	—	—	14	(1)	15	—	—	14
Other investments	—	—	36	—	36	—	—	36	—	36
Total assets	6,428	3,660	1,716	3,519	15,323	6,709	3,719	1,739	3,519	15,686
Liabilities										
Commodity derivative liabilities										
Economic hedges	(415)	(3,317)	(1,203)	—	(4,935)	(415)	(3,317)	(1,470)	—	(5,202)
Proprietary trading	—	(164)	(15)	—	(179)	—	(164)	(15)	—	(179)
Effect of netting and allocation of collateral[g] [h]	415	3,007	1,081	—	4,503	415	3,007	1,081	—	4,503
Commodity derivative liabilities subtotal	—	(474)	(137)	—	(611)	—	(474)	(404)	—	(878)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	—	—	—	—	—	(4)	—	—	(4)

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	Generation					Exelon				
As of March 31, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Economic hedges	(1)	(4)	—	—	(5)	(1)	(4)	—	—	(5)
Effect of netting and allocation of collateral	1	3	—	—	4	1	3	—	—	4
Interest rate and foreign currency derivative liabilities subtotal	—	(1)	—	—	(1)	—	(5)	—	—	(5)
Deferred compensation obligation	—	(35)	—	—	(35)	—	(138)	—	—	(138)
Total liabilities	—	(510)	(137)	—	(647)	—	(617)	(404)	—	(1,021)
Total net assets	$6,428	$3,150	$1,579	$ 3,519	$14,676	$6,709	$3,102	$1,335	$ 3,519	$14,665

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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
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	3	—	—	3	—	6	—	—	6
Economic hedges	—	10	—	—	10	—	10	—	—	10

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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
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 $371 million and $259 million at March 31, 2018 and December 31, 2017 and restricted cash of $23 million and $127 million at March 31, 2018 and December 31, 2017. Exelon excludes cash of $531 million and $389 million at March 31, 2018 and December 31, 2017 and restricted cash of $51 million and $145 million at March 31, 2018 and December 31, 2017 and includes long-term restricted cash of $103 million and $85 million at March 31, 2018 and December 31, 2017, which is reported in Other deferred debits on the Consolidated Balance Sheets.

(b) Includes $53 million and $77 million of cash received from outstanding repurchase agreements at March 31, 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 $2 million and less than $1 million, which have a total notional amount of $949 million and $811 million at March 31, 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 the company's exposure to credit or market loss.

(d) Excludes net liabilities of $84 million and $82 million at March 31, 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 $1 million at March 31, 2018. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(f) The amount of unrealized gains/(losses) at Generation totaled less than $1 million and $1 million for the three months ended March 31, 2018 and March 31, 2017, respectively. The amount of unrealized gains/(losses) at Exelon totaled $1 million and $2 million for the three months ended March 31, 2018 and March 31, 2017, respectively.

(g) Collateral posted/(received) from counterparties totaled $80 million, $418 million and $186 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 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), $156 million represents variation margin on the exchanges as of March 31, 2018. Of the collateral posted/(received), $(117) million represents variation margin on the exchanges as of December 31, 2017.

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Exelon and Generation hold investments without readily determinable fair values with carrying amounts of $68 million as of March 31, 2018. Changes were immaterial in fair value, cumulative adjustments and impairments for the three months ended March 31, 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 March 31, 2018 and December 31, 2017:

	ComEd				PECO				BGE			
As of March 31, 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)]	$93	$ —	$—	$93	$6	$ —	$ —	$6	$—	$ —	$ —	$ —
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	93	—	—	93	13	10	—	23	6	—	—	6
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(4)	—	(4)
Mark-to-market derivative liabilities[(c)]	—	—	(267)	(267)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(267)	(275)	—	(11)	—	(11)	—	(4)	—	(4)
Total net assets (liabilities)	$93	$ (8)	$(267)	$(182)	$13	$ (1)	$ —	$12	$6	$ (4)	$ —	$ 2
	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 March 31, 2018 and December 31, 2017 and includes long-term restricted cash of $83 million and $62 million at March 31, 2018 and December 31, 2017, which is reported in Other deferred debits on the Consolidated Balance Sheets. PECO excludes cash of $20 million and $47 million at March 31, 2018 and December 31, 2017. BGE

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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excludes cash of $22 million and $17 million at March 31, 2018 and December 31, 2017 and restricted cash of $2 million and $1 million at March 31, 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 months ended March 31, 2018 and March 31, 2017, respectively.

(c) The Level 3 balance consists of the current and noncurrent liability of $24 million and $243 million, respectively, at March 31, 2018, and $21 million and $235 million, respectively, at December 31, 2017, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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 March 31, 2018 and December 31, 2017:

	As of March 31, 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)]	$67	$ —	$ —	$67	$83	$ —	$ —	$83
Rabbi trust investments								
Cash equivalents	72	—	—	72	72	—	—	72
Fixed income	—	10	—	10	—	12	—	12
Life insurance contracts	—	23	23	46	—	23	22	45
Rabbi trust investments subtotal[(b)]	72	33	23	128	72	35	22	129
Total assets	139	33	23	195	155	35	22	212
Liabilities								
Deferred compensation obligation	—	(23)	—	(23)	—	(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	—	(23)	—	(23)	—	(25)	—	(25)
Total net assets	$139	$ 10	$ 23	$172	$155	$ 10	$ 22	$187

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Pepco				DPL				ACE			
As of March 31, 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]	$33	$ —	$ —	$33	$ —	$ —	$ —	$ —	$27	$ —	$ —	$27
Rabbi trust investments												
Cash equivalents	44	—	—	44	—	—	—	—	—	—	—	—
Fixed income	—	10	—	10	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	23	46	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[b]	44	33	23	100	—	—	—	—	—	—	—	—
Total assets	77	33	23	133	—	—	—	—	27	—	—	27
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$77	$29	$23	$129	$ —	$(1)	$ —	$(1)	$27	$ —	$ —	$27

	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 $36 million and $12 million at March 31, 2018 and December 31, 2017, respectively, and includes long-term restricted cash of $20 million and $23 million at March 31, 2018 and December 31, 2017, respectively, which is reported in Other deferred debits on the Consolidated Balance Sheets. Pepco excludes cash of $15 million and $4 million at March 31, 2018 and December 31, 2017, respectively. DPL excludes cash of $7 million and $2 million at March 31, 2018 and December 31, 2017, respectively. ACE excludes cash of $10 million and $2 million at March 31, 2018 and December 31, 2017, respectively, and includes long-term restricted cash of $20 million and $23 million at March 31, 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, Pepco, DPL and ACE totaled less than $1 million for the three months ended March 31, 2018 and March 31, 2017.

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

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(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 months ended March 31, 2018 and 2017:

	Generation					ComEd	PHI		Exelon
Three Months Ended March 31, 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 (c)	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	—	—	184 (a)	1	185	—	1	—	186
Included in noncurrent payables to affiliates	7	—	—	—	7	—	—	(7)	—
Included in payable for Zion Station decommissioning	—	4	—	—	4	—	—	—	4
Included in regulatory assets/liabilities	—	—	—	—	—	(11) (b)	—	7	(4)
Change in collateral	—	—	105	—	105	—	—	—	105
Purchases, sales, issuances and settlements									
Purchases	2	—	88	—	90	—	—	—	90
Sales	—	—	(3)	—	(3)	—	—	—	(3)
Settlements	(48)	—	—	—	(48)	—	—	—	(48)
Transfers into Level 3	—	—	(8)	—	(8)	—	—	—	(8)
Transfers out of Level 3	—	—	—	(2)	(2)	—	—	—	(2)
Balance at March 31, 2018	$609	$ 16	$ 918	$ 36	$ 1,579	$ (267)	$ 23	$ —	$ 1,335
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2018	$—	$ —	$ 256	$ 1	$ 257	$ —	$ 1	$ —	$ 258

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Generation					ComEd	PHI		Exelon
Three Months Ended March 31, 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	3	—	(43) [a]	1	(39)	—	1	—	(38)
Included in noncurrent payables to affiliates	9	—	—	—	9	—	—	(9)	—
Included in regulatory assets/liabilities	—	—	—	—	—	(24) [b]	—	9	(15)
Change in collateral	—	—	38	—	38	—	—	—	38
Purchases, sales, issuances and settlements									
Purchases	17	1	69	2	89	—	—	—	89
Sales	—	—	(2)	—	(2)	—	—	—	(2)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(23)	—	—	—	(23)	—	—	—	(23)
Transfers into Level 3	—	—	(1)	—	(1)	—	—	—	(1)
Transfers out of Level 3	—	—	11	(5)	6	—	—	—	6
Balance as of March 31, 2017	$683	$ 20	$ 565	$ 40	$ 1,308	$ (282)	$ 20	$ —	$1,046
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of March 31, 2017	$2	$ —	$ 59	$ —	$ 61	$ —	$ 1	$ —	$62

(a) Includes a reduction for the reclassification of $72 million and $102 million of realized gains due to the settlement of derivative contracts for the three months ended March 31, 2018 and March 31, 2017, respectively.

(b) Includes $17 million of decreases in fair value and an increase for realized losses due to settlements of $6 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2018. Includes $30 million of decreases in fair value and an increase for realized losses due to settlements of $6 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2017.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 months ended March 31, 2018 and 2017:

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net[(a)]
Total gains (losses) included in net income for the three months ended March 31, 2018	$335	$ (151)	$ 1	$ 1	$335	$ (151)	$ 1	$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2018	309	(53)	1	1	309	(53)	1	1

	Generation			PHI	Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended March 31, 2017	$88	$ (131)	$ 3	$ 1	$88	$ (131)	$ 4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2017	140	(81)	2	1	140	(81)	3

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(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation, accrued interest on a convertible promissory note at Generation and the life insurance contracts held by PHI and Pepco.

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 (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). 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 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

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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 March 31, 2018, Generation has outstanding commitments to invest in equities, fixed income, middle market lending, private equity and real estate investments of approximately $208 million, $65 million, $386 million, $194 million, and $107 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 March 31, 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 March 31, 2018, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.

See Note 13 — Nuclear Decommissioning for further discussion on the NDT fund investments.

Rabbi Trust Investments (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The Rabbi trusts assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of money market funds, mutual funds, fixed income securities and life insurance policies. 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.

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Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, 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. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 — Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). 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.

Rabbi Trust Investments - Life insurance contracts (Exelon, PHI, Pepco, DPL and ACE). 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 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 $2.99 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.

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

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 more 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 March 31, 2018	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives — Economic Hedges (Exelon and Generation)[a][b]	$ 689	Discounted Cash Flow	Forward power price	$1	- $202
			Forward gas price	$1.12	- $12.80
		Option Model	Volatility percentage	10%	- 227%
Mark-to-market derivatives — Proprietary trading (Exelon and Generation)[a][b]	$ 43	Discounted Cash Flow	Forward power price	$4	- $202
Mark-to-market derivatives (Exelon and ComEd)	$ (267)	Discounted Cash Flow	Forward heat rate[c]	9x	- 10x
			Marketability reserve	4%	- 8%
			Renewable factor	87%	- 122%

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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 $186 million and $81 million as of March 31, 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 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 March 31, 2018 and December 31, 2017, $8 million and $4 million of cash collateral held, respectively, 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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The following table provides a summary of the derivative fair value balances recorded by the Registrants as of March 31, 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)	$3,343	$ 166	$ (2,533)	$ 976	$ —	$ —	$ —	$ —	$ 976
Mark-to-market derivative assets (noncurrent assets)	1,758	43	(1,286)	515	—	—	—	—	515
Total mark-to-market derivative assets	5,101	209	(3,819)	1,491	—	—	—	—	1,491
Mark-to-market derivative liabilities (current liabilities)	(3,185)	(151)	2,945	(391)	(24)	—	—	—	(415)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,750)	(28)	1,558	(220)	(243)	—	—	—	(463)
Total mark-to-market derivative liabilities	(4,935)	(179)	4,503	(611)	(267)	—	—	—	(878)
Total mark-to-market derivative net assets (liabilities)	$166	$ 30	$ 684	$ 880	$ (267)	$ —	$ —	$ —	$ 613

(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 $192 million and $103 million, respectively, and current and noncurrent liabilities are shown net of collateral of $220 million and $169 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $684 million at March 31, 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), $156 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 months ended March 31, 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 March 31,	
	2018	2017
Income Statement Location	Gain (Loss)	
Operating revenues	$(100)	$46
Purchased power and fuel	(167)	(93)
Total Exelon and Generation	$(267)	$(47)

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 March 31, 2018, the percentage of expected generation hedged is 91%-94%, 63%-66% and 33%-36% 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 2016 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-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, 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 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.

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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 months ended March 31, 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 March 31,	
Income Statement Location	2018	2017
	Gain (Loss)	
Operating revenues	$2	$(1)

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 utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest

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rate derivatives to lock in rate levels, which are typically designated as cash flow hedges to manage interest rate risk. To manage foreign exchange rate exposure associated with 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 March 31, 2018:

	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)	$—	$ 5	$ (3)	$ 2	$ —	$ 2
Mark-to-market derivative assets (noncurrent assets)	12	1	(1)	12	—	12
Total mark-to-market derivative assets	12	6	(4)	14	—	14
Mark-to-market derivative liabilities (current liabilities)	—	(3)	3	—	—	—
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(2)	1	(1)	(4)	(5)
Total mark-to-market derivative liabilities	—	(5)	4	(1)	(4)	(5)
Total mark-to-market derivative net assets (liabilities)	$12	$ 1	$ —	$ 13	$ (4)	$ 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.

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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 (liabilities)	$ 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.

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 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 March 31,			
		2018	2017	2018	2017
	Income Statement Location	Loss on Swaps		Gain on Borrowings	
Exelon	Interest expense	$ (7)	$ (4)	$ 13	$ 8

The table below provides the notional amounts of fixed-to-floating hedges outstanding held by Exelon at March 31, 2018 and December 31, 2017:

	As of March 31, 2018	December 31, 2017
Fixed-to-floating hedges	$ 800	$ 800

During the three months ended March 31, 2018 and 2017, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $6 million gain and a $4 million gain, respectively.

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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. To mitigate interest rate risk, Exelon and Generation enter into floating-to-fixed interest rate swaps to manage a portion of interest rate exposure associated with debt issuances. The table below provides the notional amounts of floating-to-fixed hedges outstanding held by Exelon and Generation as of March 31, 2018.

	As of March 31, 2018	December 31, 2017
Floating-to-fixed hedges	$636	$ 636

The tables below provide the activity of OCI related to cash flow hedges for the three months ended March 31, 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 March 31, 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		7	8
AOCI derivative loss at March 31, 2018		$ (9)	$ (6)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended March 31, 2017	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash 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	4 (a)	4 (a)
AOCI derivative loss at March 31, 2017		$ (13)	$ (11)

(a) Amount is net of related income tax expense of $3 million for the three months ended March 31, 2017.

During the three months ended March 31, 2018 and 2017, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships 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.

Economic Hedges (Interest Rate and Foreign Exchange Risk)
Exelon and Generation executes 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. Generation also enters into interest

rate derivative contracts and foreign exchange currency swaps

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("treasury") to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars.

At March 31, 2018 and December 31, 2017, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The following table provides notional amounts outstanding held by Exelon and Generation at March 31, 2018 and December 31, 2017 related to foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

	As of March 31, 2018	December 31, 2017
Foreign currency exchange rate swaps	$ 87	$ 94

For the three months ended March 31, 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.

	Income Statement Location	Three Months Ended March 31, 2018 Gain (Loss)	2017
Generation	Operating Revenues	$ 2	$ (2)
Generation	Purchased Power and Fuel	(1)	—
Total Generation		$ 1	$ (2)

	Income Statement Location	Three Months Ended March 31, 2018 Gain (Loss)	2017
Exelon	Operating Revenues	$ 2	$ (2)
Exelon	Purchased Power and Fuel	(1)	—
Total Exelon		$ 1	$ (2)

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 months ended March 31, 2018 and 2017 Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses).

	Three Months Ended March 31,	
	2018	2017
Income Statement Location	Gain (Loss)	
Operating Revenues	$ —	$ (1)

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 March 31, 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 $31 million, $21 million, $25 million, $34 million, $9 million, and $5 million as of March 31, 2018, respectively.

Rating as of March 31, 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	$ 986	$ 1	$ 985	2	$ 412
Non-investment grade	112	46	66		
No external ratings					
Internally rated — investment grade	223	—	223		
Internally rated — non-investment grade	100	17	83		
Total	$ 1,421	$ 64	$ 1,357	2	$ 412

Net Credit Exposure by Type of Counterparty	As of March 31, 2018
Financial institutions	$ 189
Investor-owned utilities, marketers, power producers	656
Energy cooperatives and municipalities	438
Other	74
Total	$ 1,357

(a) As of March 31, 2018, credit collateral held from counterparties where Generation had credit exposure included $41 million of cash and $23 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 March 31, 2018, ComEd's net credit exposure to suppliers was less than $1 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 March 31, 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. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of March 31, 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 March 31, 2018, BGE's net credit exposure to suppliers was immaterial.

BGE’s regulated gas business is exposed to market-price risk. At March 31, 2018, BGE had credit exposure of approximately $12 million 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.

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 March 31, 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 March 31, 2018, DPL had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

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 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.

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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 Feature	March 31, 2018	December 31, 2017
Gross fair value of derivative contracts containing this feature[(a)]	$(2,141)	$ (926)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	1,562	577
Net fair value of derivative contracts containing this feature[(c)]	$(579)	$ (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 $742 million and letters of credit posted of $493 million and cash collateral held of $66 million and letters of credit held of $46 million as of March 31, 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 $1.9 billion and $1.8 billion as of March 31, 2018 and December 31, 2017, respectively. 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 March 31, 2018, Generation's and Exelon's swaps were in an asset position of $13 million and $9 million, respectively.

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

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 March 31, 2018, ComEd held approximately $9 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 March 31, 2018, ComEd held approximately $14 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 March 31, 2018, ComEd held approximately $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of March 31, 2018, it would have been required to post approximately $10 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 March 31, 2018, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of March 31, 2018, PECO could have been required to post approximately $33 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 March 31, 2018, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of March 31, 2018, BGE could have been required to post approximately $49 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 March 31, 2018, DPL could have been required to post an additional amount of approximately $14 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.

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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 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 March 31, 2018 and December 31, 2017:

Commercial Paper Borrowings	March 31, 2018	December 31, 2017
Exelon	$1,154	$ 427
Generation	165	—
ComEd	317	—
PECO	220	—
BGE	45	77
PHI[(a)]	407	350
Pepco	60	26
DPL	211	216
ACE	136	108

(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. The loan agreement is reflected in Exelon’s Consolidated Balance Sheet within Short-Term borrowings.
Credit Agreements
As of March 15, 2018, the credit agreement for Generation’s $30 million bilateral credit facility was amended to increase the overall facility size to $95 million. This facility will solely be used by Generation to issue letters of credit.

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Long-Term Debt
Issuance of Long-Term Debt
During the three months ended March 31, 2018, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.72 %	April 30, 2018	$ 1	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Energy Efficiency Project Financing	3.17 %	April 30, 2018	$ 1	Funding to install energy conservation measures in Brooklyn, NY.
Generation	Energy Efficiency Project Financing	2.61 %	September 30, 2018	$ 2	Funding to install energy conservation measures for the Pensacola 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.
PECO	First and Refunding Mortgage Bonds	3.90 %	March 1, 2048	$ 325	Refinance a portion of maturing mortgage bonds.

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) 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 further information.
The Registrants have completed their assessment of 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.

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For property acquired and placed-in-service after September 27, 2017, the TCJA repeals 50% bonus depreciation for all taxpayers and in addition provides for 100% expensing for taxpayers other than regulated utilities. As a result, Generation will be required to evaluate the contractual terms of its fourth quarter 2017 capital additions and determine if they qualify for 100% expensing under the TCJA as compared to 50% bonus depreciation under prior tax law. Similarly, the Utility Registrants will be required to evaluate the contractual terms of their fourth quarter 2017 capital additions to determine whether they still qualify for the prior tax law’s 50% bonus depreciation as compared to no bonus depreciation pursuant to the TCJA.
At Generation, any required changes to the provisional estimates during the measurement period related to the above item would result in an adjustment to current income tax expense at 35% and a corresponding adjustment to deferred income tax expense at 21% and such changes could be material to Generation’s future results of operations. At the Utility Registrants, any required changes to the provisional estimates would result in the recording of regulatory assets or liabilities to the extent such amounts are probable of settlement or recovery through customer rates and a net change to income tax expense for any other amounts.
The Registrants expect any final adjustments to the provisional amounts to be recorded by the third quarter of 2018, which could be material to the Registrants’ future results of operations or financial positions. The accounting for all other applicable provisions of the TCJA is considered complete based on our current interpretation of the provisions of the TCJA as enacted as of December 31, 2017.
While the Registrants have recorded the impacts of the TCJA based on their interpretation of the provisions as enacted, it is expected that technical corrections or other forms of guidance will be issued during 2018, which could result in material changes to previously finalized provisions. At this time, most states have not provided guidance regarding TCJA impacts and may issue guidance in 2018 which may impact estimates.
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:

	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 remains in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. Refer to Note 3 - Regulatory Matters for additional information.

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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. Refer to Note 3 - 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, rate regulators could require the passing back of amounts to customers over shorter time frames.

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 March 31, 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	4.1	2.4	8.2	(3.9)	6.3	4.6	1.7	6.3	6.6
Qualified nuclear decommissioning trust fund income	(0.4)	(1.3)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.3)	(4.3)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.3)
Plant basis differences	(2.7)	—	0.1	(14.2)	(0.7)	(2.6)	(3.4)	(1.3)	(2.6)
Production tax credits and other credits	(2.8)	(9.5)	(0.1)	—	—	—	—	—	—
Noncontrolling interests	(0.7)	(2.5)	—	—	—	—	—	—	—
Excess deferred tax amortization	(6.0)	—	(7.5)	(4.8)	(8.6)	(10.6)	(12.8)	(7.9)	(8.7)
Other	(2.8)	(1.3)	0.3	0.2	—	—	(0.3)	0.5	(3.5)
Effective income tax rate	8.4%	4.5%	21.8%	(1.8)%	17.9%	12.2%	6.1%	18.4%	12.5%

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	Three Months Ended March 31, 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	0.9	1.0	4.9	0.1	5.2	4.9	4.6	5.3	5.6
Qualified nuclear decommissioning trust fund income	3.5	7.8	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.4)	(0.7)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.3)	(0.4)
Plant basis differences	(2.4)	—	(0.2)	(13.2)	(0.9)	(3.8)	(5.8)	(1.9)	(3.4)
Production tax credits and other credits	(0.7)	(1.5)	—	—	—	—	—	—	—
Noncontrolling interest	—	0.1	—	—	—	—	—	—	—
Merger expenses[b]	(11.5)	(3.4)	—	—	—	(42.4)	(34.2)	(21.9)	(167.1)
Fitzpatrick bargain purchase gain	(6.6)	(14.8)	—	—	—	—	—	—	—
Other	(0.1)	(0.4)	—	0.3	(0.2)	(0.4)	0.5	—	(3.0)
Effective income tax rate	17.7%	23.1%	39.5%	22.1%	39.0%	(6.9)%	0.0%	16.2%	(133.3)%

(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) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.

Accounting for Uncertainty in Income Taxes

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

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
March 31, 2018	$ 733	$ 464	$ 2	$ —	$120	$125	$ 59	$ 21	$ 14

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

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 March 31, 2018, Exelon and ComEd have approximately $33 million and $2 million, respectively, of unrecognized federal and state income tax benefits that could significantly decrease within the 12 months after the reporting date due to a final resolution of the like-kind exchange litigation described below. The recognition of these unrecognized tax benefits would decrease Exelon and ComEd's effective tax rate.

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Settlement of Income Tax Audits, Refund Claims, and Litigation
As of March 31, 2018, Exelon, Generation, BGE, PHI, Pepco, DPL, and ACE have approximately $679 million, $465 million, $120 million, $94 million, $59 million, $21 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 $458 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, Pepco, DPL, and ACE, if recognized, may be included in future regulated base rates and that portion would have no impact to the 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 and a decision is expected in 2018.
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 by 2022.
In the second quarter of 2018, Exelon, Generation, PHI, DPL, and Pepco expect to record an estimated one-time increase to deferred income taxes of approximately $17 million, $5 million, $18 million, $1 million and $17 million, respectively. At PHI, DPL and Pepco, the increase to the Maryland deferred income tax liability will be 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, DPL's or Pepco's future results of operations.

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13. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

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

The 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 March 31, 2018:

Nuclear decommissioning ARO at December 31, 2017[(a)]	$9,662
Accretion expense	117
Net increase due to changes in, and timing of, estimated future cash flows	32
Costs incurred related to decommissioning plants	(4)
Nuclear decommissioning ARO at March 31, 2018[(a)]	$9,807

(a) Includes $64 million and $13 million for the current portion of the ARO at March 31, 2018 and December 31, 2017, respectively, which is included in Other current liabilities on Exelon’s and Generation’s Consolidated Balance Sheets.

During the three months ended March 31, 2018, Generation’s total nuclear ARO increased by approximately $145 million, primarily reflecting the accretion of the ARO liability due to the passage of time and the impact of the February 2, 2018 announcement to retire Oyster Creek at the end of its current operating cycle by October 2018. Refer to Note 8 — Early Plant Retirements for additional information regarding the announced early retirement of Oyster Creek.

Nuclear Decommissioning Trust Fund Investments

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 $13,275 million and $13,349 million at March 31, 2018 and December 31, 2017, respectively.

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The following table provides net unrealized gains (losses) on NDT funds for the three months ended March 31, 2018 and 2017:

	Exelon and Generation Three Months Ended March 31,	
	2018	2017
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units[a]	$(75)	$222
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units[b][c]	(96)	166

(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 $(2) million and $(1) million of net unrealized losses related to the Zion Station pledged assets for the three months ended March 31, 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 in 2018 and 2017, respectively.

(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.

Refer to 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

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. Generation has a liability of approximately $115 million which is included within the nuclear decommissioning ARO at March 31, 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 March 31, 2018 and December 31, 2017:

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	Exelon and Generation	
	March 31, 2018	December 31, 2017
Carrying value of Zion Station pledged assets[(a)]	$ 30	$ 39
Payable to Zion Solutions[(b)(c)]	28	37
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(d)]	949	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

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.

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

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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. Refer to Note 4 — Mergers, Acquisitions and Dispositions for additional discussion 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%.

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 months ended March 31, 2018 and 2017.

	Pension Benefits Three Months Ended March 31,		Other Postretirement Benefits Three Months Ended March 31,	
	2018	2017[(a)]	2018	2017[(a)]
Components of net periodic benefit cost:				
Service cost	$ 101	$ 95	$ 28	$ 26
Interest cost	201	210	43	45
Expected return on assets	(312)	(299)	(43)	(41)
Amortization of:				
Prior service benefit	—	—	(46)	(47)
Actuarial loss	157	152	16	16
Net periodic benefit cost	$ 147	$ 158	$ (2)	$ (1)

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

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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 months ended March 31, 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 for the three months ended March 31, 2018 and 2017, while the non-service cost components are included in Other, net and Regulatory assets for the three months ended March 31, 2018 and in Other, net and Property, plant and equipment for the three months ended March 31, 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 on their consolidated financial statements for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31,	
Pension and Other Postretirement Benefit Costs	2018	2017
Exelon[(a)(b)]	$145	$157
Generation[(b)]	51	54
ComEd	45	44
PECO	5	7
BGE	15	16
BSC[(c)]	14	12
PHI[(a)(d)]	15	24
Pepco	4	7
DPL	—	3
ACE	3	3
PHISCO[(d)]	8	11

(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 or ACE 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 months ended March 31, 2018 and 2017, respectively.

	Three Months Ended March 31,	
Savings Plan Matching Contributions	2018	2017
Exelon[(a)(b)]	$32	$ 30
Generation[(b)]	15	14
ComEd	7	7
PECO	2	2
BGE	2	2
BSC[(c)]	3	2
PHI[(a)(d)]	3	3
Pepco	1	1
DPL	1	1
PHISCO[(d)]	1	1

(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, 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 or DPL 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 three months ended March 31, 2018 and 2017:

Three Months Ended March 31, 2018	Gains and (losses) on Cash Flow Hedges	Unrealized Gains and (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	8	—	18	1	—	27
Amounts reclassified from AOCI[b]	—	—	44	—	—	44
Net current-period OCI	8	—	62	1	—	71
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(10) [c]	—	—	—	(10)
Ending balance	$ (6)	$ —	$ (2,936)	$ (22)	$ (1)	$ (2,965)
Generation[a]						
Beginning balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
OCI before reclassifications	7	—	—	(1)	—	6
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	7	—	—	(1)	—	6
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	(3) [c]	—	—	—	(3)
Ending balance	$ (9)	$ —	$ —	$ (24)	$ (1)	$ (34)
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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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

Three Months Ended March 31, 2017	Gains and (losses) on Cash Flow Hedges	Unrealized Gains and (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	1	(59)	1	5	(50)
Amounts reclassified from AOCI[(b)]	4	—	36	—	—	40
Net current-period OCI	6	1	(23)	1	5	(10)
Ending balance	$ (11)	$ 5	$ (2,633)	$ (29)	$ (2)	$(2,670)
Generation[(a)]						
Beginning balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$(54)
OCI before reclassifications	2	—	—	1	6	9
Amounts reclassified from AOCI[(b)]	4	—	—	—	—	4
Net current-period OCI	6	—	—	1	6	13
Ending balance	$ (13)	$ 2	$ —	$ (29)	$ (1)	$(41)
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 interest. 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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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(Dollars in millions, except per share data, unless otherwise noted)

ComEd, PECO, BGE, PHI, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three months ended March 31, 2018 and 2017. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the three months ended March 31, 2018 and 2017.

Three Months Ended March 31, 2018

Details about AOCI components	Items reclassified out of AOCI[a]	Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	
Amortization of pension and other postretirement benefit plan items		
Prior service costs[b]	$ 23	
Actuarial losses[b]	(83)	
Total before tax	(60)	
Tax benefit	16	
Net of tax	$ (44)	
Total Reclassifications	$ (44)	Comprehensive income

Three Months Ended March 31, 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 and (losses) on cash flow hedges			
Other cash flow hedges	$ (7)	$ (7)	Interest expense
Total before tax	(7)	(7)	
Tax benefit	3	3	
Net of tax	$ (4)	$ (4)	Comprehensive income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 23	$ —	
Actuarial losses[b]	(81)	—	
Total before tax	(58)	—	
Tax benefit	22	—	
Net of tax	$ (36)	$ —	
Total Reclassifications	$ (40)	$ (4)	Comprehensive income

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31, 2018	2017
Exelon		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	$6	$10
Actuarial loss reclassified to periodic benefit cost	(22)	(32)
Pension and non-pension postretirement benefit plans valuation adjustment	(7)	—
Change in unrealized (loss) on cash flow hedges	(3)	(1)
Change in unrealized (loss) on investments in unconsolidated affiliates	(1)	(4)
Change in unrealized (loss) on marketable securities	—	(1)
Total	$(27)	$(28)
Generation		
Change in unrealized (loss) on cash flow hedges	$(3)	$(1)
Change in unrealized (loss) on investments in unconsolidated affiliates	(1)	(3)
Total	$(4)	$(4)

16. Earnings Per Share and Equity (Exelon)

Earnings per Share

Basic earnings per share is computed by dividing net income attributable to common stockholders 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 March 31, 2018	2017
Exelon		
Net income attributable to common shareholders	$585	$990
Weighted average common shares outstanding — basic	966	928
Assumed exercise and/or distributions of stock-based awards	2	2
Weighted average common shares outstanding — diluted	968	930

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 5 million and 9 million for the three months ended March 31, 2018 and 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 months ended March 31, 2018 and 2017. Refer to Note 19 — Shareholders' Equity of the Exelon 2017 Form 10-K for further information regarding the equity units.

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

Under share repurchase programs, 2 million shares of common stock are held as treasury stock with a cost of $123 million as of March 31, 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 further discussion 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 March 31, 2018:

Description	Expected Payment Period	Pepco	DPL	ACE	PHI	Exelon
Rate credits	2016 - 2017	$ 91	$ 67	$ 101	$ 259	$ 259
Energy efficiency	2016 - 2021	—	—	—	—	122
Charitable contributions	2016 - 2026	28	12	10	50	50
Delivery system modernization	Q2 2017	—	—	—	—	22
Green sustainability fund	Q2 2017	—	—	—	—	14
Workforce development	2016 - 2020	—	—	—	—	17
Other		1	5	—	6	29
Total commitments		$ 120	$ 84	$ 111	$ 315	$ 513
Remaining commitments		$ 75	$ 12	$ 8	$ 95	$ 165

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 by 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 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.

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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 55MW 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 March 31, 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. Refer to Note 23 - Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2017 Form 10-K for additional information regarding the Constellation Merger Commitments.

Commercial Commitments (All Registrants)

The Registrants' commercial commitments as of March 31, 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)]	$1,586	$ 1,533	$ 2	$ 1	$ 5	$1	$ 1	$—	$—
Surety bonds[(b)]	1,651	1,463	9	9	10	66	32	4	5
Financing trust guarantees	378	—	200	178	—	—	—	—	—
Guaranteed lease residual values[(c)]	22	—	—	—	—	22	7	9	6
Total commercial commitments	$3,637	$ 2,996	$ 211	$ 188	$ 15	$89	$ 40	$ 13	$ 11

(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 $58 million, $17 million of which is a guarantee by Pepco, $24 million by DPL and $16 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

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reactor owners for such claims from any single incident. As of March 31, 2018, the current liability limit per incident is $13.2 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors 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 $13.0 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 $13.2 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 is estimated to be $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 three months ended March 31, 2018, with cash expected to be received during the second quarter 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 $360 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 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. 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

ComEd, PECO, BGE and DPL have identified sites where former MGP 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 2022.
- 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 former gas manufacturing or purification sites, 9 of which the remediation has been completed and approved by the MDE and 4 that require some level of remediation and/or ongoing activity. BGE has determined that a loss associated with these sites is probable and has recorded an estimated liability, which is included in the table below. However, it is reasonably possible that BGE's cost of remediation for one of its sites could be up to $13 million.
- DPL has identified 3 sites, 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 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.

As of March 31, 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:

March 31, 2018	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 462	$ 313
Generation	117	—
ComEd	283	281
PECO	29	28
BGE	5	4
PHI	28	—
Pepco	26	—
DPL	1	—
ACE	1	—

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. 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 draft final Remedial Investigation and Feasibility Study (RI/FS) to the EPA in January 2018, which formed the basis for EPA’s proposed remedy selection, as further 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 February 1, 2018, the EPA announced its proposed remedy involving partial excavation of the site with an enhanced landfill cover. The proposed remedy was open for public comment through April 23, 2018 and Generation currently expects that a ROD will be issued during the third quarter of 2018. Thereafter, the EPA will seek to enter into a Consent Decree with the PRPs to effectuate the remedy, which Generation currently expects will occur in late 2018 or early 2019. 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 $340 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 ultimate 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. The PRPs have been provided with a draft statement of work that will form the basis of 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 2018 so that settlement discussions could proceed. Generation has determined that a loss associated with this matter is probable under its indemnification agreement with Cotter and has recorded an estimated liability, which is included in the table above.

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. The complaints do not contain specific damage claims. In the event of a finding of liability against Cotter, it is reasonably possible 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, and that has been upheld on appeal. The parties have engaged in settlement discussions pursuant to court-ordered mediation and it is expected that resolution of this matter will not have a material, unfavorable impact on Exelon’s and Generation's financial conditions, results of operations and cash flows.

Benning Road Site. 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. 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 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. DOEE has advised the Consultative Working Group that the federal and DOEE authorities conducted the remedial investigation and a draft of that report was released to the public on April 1, 2018. Written comments will be accepted by the Agencies until May 14, 2018 and a Public Meeting to present the finding of the RI is scheduled for April 24, 2018. Pepco intends to submit comments, participate in the Public Hearing, and continue its outreach efforts as appropriate to the agencies, governmental officials, community organizations and other key stakeholders. A feasibility study of potential remedies is being prepared by the Agencies and is scheduled to be released in the late summer or early fall of this year. DOEE currently is working under a statutorily mandated date to complete the Record of Decision selecting the final remedy for the project by June 30, 2018. However, on January 11, 2018 the DOEE requested at a hearing of the District of Columbia Council Committee of the Environment that this statutory deadline be extended until December 31, 2019 to reflect the time necessary to complete the investigation. A recommendation by the Committee to the DC Council is expected in the near future. The District of Columbia Council will make the final determination to extend the deadline. 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. It is anticipated that Pepco will likely be in a better position to estimate that range of loss when the draft Feasibility Study for the Project is released. The timing for that release is currently scheduled for late this summer or early fall.

Conectiv Energy Wholesale Power Generation Sites. 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. Predecessor PHI was obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of $10 million. According to PHI’s estimates, 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 predecessor PHI recorded an estimated 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 Predecessor 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.

Brandywine Fly Ash Disposal Site. 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

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

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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.

Asbestos Personal Injury Claims

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

At March 31, 2018 and December 31, 2017, Generation had recorded estimated liabilities of approximately $76 million and $78 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2018, approximately $21 million of this amount related to 232 open claims presented to Generation, while the remaining $55 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.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee’s disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee’s last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court’s ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee’s last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court's ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been accrued for on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois' Workers' Compensation Act and the Workers' Occupational Diseases Act barred an employee from bringing a direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. As a result of this ruling, Exelon, Generation, and ComEd have not recorded an increase to the asbestos-related bodily injury liability as of March 31, 2018.

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 8 & 9 on the grounds that the total investment in Mystic 8 & 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

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 a reasonable possibility, 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 months ended March 31, 2018 and 2017.

	Three Months Ended March 31, 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	$46	$ 46	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	56	56	—	—	—	—	—	—	—
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(75)	(75)	—	—	—	—	—	—	—
Non-regulatory agreement units	(96)	(96)	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(2)	(2)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	24	24	—	—	—	—	—	—	—
Total decommissioning-related activities	(47)	(47)	—	—	—	—	—	—	—
Investment income	4	2	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	2	1	—	—	—	—	—	—	—
AFUDC — Equity	18	—	6	2	4	6	5	1	—
Non-service net periodic benefit cost	(10)	—	—	—	—	—	—	—	—
Other	5	—	2	—	—	5	3	1	1
Other, net	$(28)	$ (44)	$ 8	$ 2	$ 4	$11	$ 8	$ 2	$ 1

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

	Three Months Ended March 31, 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	$68	$ 68	$ —	$ —	$ —	$—	$ —	$ —	$ —
Non-regulatory agreement units	32	32	—	—	—	—	—	—	—
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	222	222	—	—	—	—	—	—	—
Non-regulatory agreement units	166	166	—	—	—	—	—	—	—
Net unrealized losses on pledged assets									
Zion Station decommissioning	(1)	(1)	—	—	—	—	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(234)	(234)	—	—	—	—	—	—	—
Total decommissioning-related activities	253	253	—	—	—	—	—	—	—
Investment income	2	2	—	—	—	—	—	—	—
Interest income related to uncertain income tax positions	1	—	—	—	—	—	—	—	—
AFUDC — Equity	17	—	2	2	4	9	5	2	2
Non-service net periodic benefit cost	(26)	—	—	—	—	—	—	—	—
Other	10	4	2	—	—	4	3	1	—
Other, net	$257	$ 259	$ 4	$ 2	$ 4	$13	$ 8	$ 3	$ 2

(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 months ended March 31, 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 March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$235	$ 32	$ 61	$ 33	$ 26	$83	$ 77	$ 6	$ —

	Three Months Ended March 31, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$224	$ 32	$ 59	$ 31	$ 26	$76	$ 71	$ 5	$ —

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[a]	$926	$ 436	$ 201	$ 68	$82	$117	$ 53	$ 32	$ 23
Amortization of regulatory assets[a]	152	—	27	7	52	66	43	13	10
Amortization of intangible assets, net[a]	13	12	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[b]	3	3	—	—	—	—	—	—	—
Nuclear fuel[c]	287	287	—	—	—	—	—	—	—
ARO accretion[d]	120	120	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$1,501	$ 858	$ 228	$ 75	$134	$183	$ 96	$ 45	$ 33

	Three Months Ended March 31, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Depreciation, amortization and accretion									
Property, plant and equipment[a]	$754	$ 289	$ 190	$ 64	$80	$112	$ 50	$ 30	$ 21
Amortization of regulatory assets[a]	128	—	18	7	48	55	32	9	14
Amortization of intangible assets, net[a]	14	13	—	—	—	—	—	—	—
Amortization of energy contract assets and liabilities[b]	2	2	—	—	—	—	—	—	—
Nuclear fuel[c]	264	264	—	—	—	—	—	—	—
ARO accretion[d]	112	110	—	—	—	—	—	—	—
Total depreciation, amortization and accretion	$1,274	$ 678	$ 208	$ 71	$128	$167	$ 82	$ 39	$ 35

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(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)
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	Three Months Ended March 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$145	$ 51	$ 45	$ 5	$ 14	$ 15	$ 4	$ —	$ 3
Loss from equity method investments	7	7	—	—	—	—	—	—	—
Provision for uncollectible accounts	64	11	8	17	8	20	6	8	5
Stock-based compensation costs	29	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(31)	(31)	—	—	—	—	—	—	—
Energy-related options[(b)]	(7)	(7)	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	2	—	1	—	—	1	—	—	—
Amortization of rate stabilization deferral	7	—	—	—	—	7	1	6	—
Amortization of debt fair value adjustment	(3)	(3)	—	—	—	—	—	—	—
Discrete impacts from EIMA and FEJA[(c)]	(4)	—	(4)	—	—	—	—	—	—
Amortization of debt costs	9	3	1	—	—	1	—	—	—
Provision for excess and obsolete inventory	13	12	1	—	—	—	—	—	—
Other	9	2	(6)	(1)	(2)	9	(1)	5	1
Total other non-cash operating activities	$240	$ 45	$ 46	$ 21	$ 20	$ 53	$ 10	$ 19	$ 9
Non-cash investing and financing activities:									
Increase (decrease) in capital expenditures not paid	$(177)	$ (131)	$ (48)	$ (25)	$ (11)	$ 61	$ 19	$ 14	$ 27
Increase in PPE related to ARO update	32	32	—	—	—	—	—	—	—
Dividends on stock compensation	1	—	—	—	—	—	—	—	—

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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	Three Months Ended March 31, 2017								
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$157	$ 54	$ 44	$7	$16	$24	$7	$3	$ 3
Loss from equity method investments	10	10	—	—	—	—	—	—	—
Provision for uncollectible accounts	34	9	7	17	5	(4)	(5)	(1)	1
Stock-based compensation costs	31	—	—	—	—	—	—	—	—
Other decommissioning-related activity[(a)]	(84)	(84)	—	—	—	—	—	—	—
Energy-related options[(b)]	(4)	(4)	—	—	—	—	—	—	—
Amortization of regulatory asset related to debt costs	2	—	1	—	—	1	—	—	—
Amortization of rate stabilization deferral	(14)	—	—	—	7	(21)	(15)	(6)	—
Amortization of debt fair value adjustment	(5)	(3)	—	—	—	(2)	—	—	—
Discrete impacts from EIMA and FEJA [(c)]	(24)	—	(24)	—	—	—	—	—	—
Amortization of debt costs	9	4	1	—	—	—	—	—	—
Provision for excess and obsolete inventory	2	1	1	—	—	—	—	—	—
Other	4	3	1	(1)	(4)	(6)	(2)	(3)	(2)
Total other non-cash operating activities	$118	$ (10)	$ 31	$23	$24	$(8)	$(15)	$(7)	$ 2
Non-cash investing and financing activities:									
Increase (decrease) in capital expenditures not paid	$(193)	$ (56)	$ (66)	$(42)	$1	$(5)	$(6)	$9	$ —
Non-cash financing of capital projects	10	10	—	—	—	—	—	—	—
Dividends on stock compensation	2	—	—	—	—	—	—	—	—

(a) Includes the elimination of NDT fund activity 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.

(c) Reflects the change in distribution rates pursuant to EIMA and FEJA, which allows for the recovery of distribution costs by a utility through a pre-established performance-based formula rate tariff. Beginning June 1, 2017, also reflects the change in energy efficiency rates pursuant to FEJA, which allows for the recovery of energy efficiency costs by a utility through a pre-established performance-based formula rate tariff. See Note 6 — Regulatory Matters for more information.

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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.

March 31, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$787	$ 610	$ 70	$ 21	$ 22	$43	$ 15	$ 7	$ 10
Restricted cash	209	127	9	5	2	40	33	—	7
Restricted cash included in other long-term assets	103	—	83	—	—	20	—	—	20
Total cash, cash equivalents and restricted cash shown in the statement of cash flows	$1,099	$ 737	$ 162	$ 26	$ 24	$103	$ 48	$ 7	$ 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 shown in the statement of cash flows	$1,190	$ 554	$ 144	$ 275	$ 18	$95	$ 40	$ 2	$ 31
March 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Cash and cash equivalents	$ 609	$ 400	$ 31	$ 28	$ 11	$109	$ 8	$ 44	$ 54
Restricted cash	254	140	3	4	43	41	33	—	7
Restricted cash included in other long-term assets	26	—	—	—	3	23	—	—	23
Total cash, cash equivalents and restricted cash shown in the statement of cash flows	$ 889	$ 540	$ 34	$ 32	$ 57	$173	$ 41	$ 44	$ 84
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 shown in the statement of cash flows	$ 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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Supplemental Balance Sheet Information
The following tables provide additional information about assets and liabilities of the Registrants as of March 31, 2018 and December 31, 2017.

March 31, 2018	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$21,905 (a)	$ 11,936 (a)	$4,391	$3,445	$3,471	$575	$3,224	$1,273	$1,086
Accounts receivable:									
Allowance for uncollectible accounts	$369	$ 115	$89	$68	$31	$66	$24	$22	$20
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 $3,263 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 $8 million and $11 million as of March 31, 2018 and December 31, 2017, respectively. The allowance for uncollectible accounts balance associated with these receivables at March 31, 2018 of $10 million consists of $3 million and $7 million for medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2017 of $11 million consists of $3 million and $8 million for medium risk and high risk segments, respectively. For further information regarding uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables, refer to Note 1 — Significant Accounting Policies of the Exelon 2017 Form 10-K.

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

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended March 31, 2018 and 2017 is as follows:
Three Months Ended March 31, 2018 and 2017

	Generation[(a)]	ComEd	PECO	BGE	PHI	Other[(b)]	Intersegment Eliminations	Exelon
Operating revenues[(c)]:								
2018								
Competitive businesses electric revenues	$ 4,509	$—	$—	$—	$—	$—	$ (391)	$4,118
Competitive businesses natural gas revenues	955	—	—	—	—	—	(8)	947
Competitive businesses other revenues	48	—	—	—	—	—	—	48
Rate-regulated electric revenues	—	1,512	634	658	1,169	—	(18)	3,955
Rate-regulated natural gas revenues	—	—	232	319	78	—	(4)	625
Shared service and other revenues	—	—	—	—	4	451	(455)	—
Total operating revenues	5,512	1,512	866	977	1,251	451	(876)	9,693
2017								
Competitive businesses electric revenues	$ 3,710	$—	$—	$—	$—	$—	$ (328)	$3,382
Competitive businesses natural gas revenues	918	—	—	—	—	—	—	918
Competitive businesses other revenues	250	—	—	—	—	—	—	250
Rate-regulated electric revenues	—	1,298	590	667	1,097	—	(8)	3,644
Rate-regulated natural gas revenues	—	—	206	284	66	—	(3)	553
Shared service and other revenues	—	—	—	—	12	419	(431)	—
Total operating revenues	4,878	1,298	796	951	1,175	419	(770)	8,747
Shared service and other revenues								
Intersegment revenues[(d)]:								
2018	$ 400	$14	$2	$6	$4	$450	$ (876)	$—
2017	328	5	1	5	12	419	(770)	—
Net income (loss):								
2018	$ 186	$165	$113	$128	$65	$(21)	$ —	$636
2017	399	141	127	125	140	39	—	971
Total assets:								
March 31, 2018	$ 48,375	$30,002	$10,218	$9,195	$21,375	$8,833	$ (10,980)	$117,018
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)
(Dollars in millions, except per share data, unless otherwise noted)

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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 March 31, 2018 include revenue from sales to PECO of $37 million, sales to BGE of $65 million, sales to Pepco of $52 million, sales to DPL of $46 million and sales to ACE of $6 million in the Mid-Atlantic region, and sales to ComEd of $194 million in the Midwest region, which eliminate upon consolidation. For the three months ended March 31, 2017, intersegment revenues for Generation include revenue from sales to PECO of $45 million, sales to BGE of $134 million, sales to Pepco of $83 million, sales to DPL of $51 million and sales to ACE of $9 million in the Mid-Atlantic region, and sales to ComEd of $5 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 March 31, 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 March 31, 2018						
Rate-regulated electric revenues	$557	$306	$310	$—	$ (4)	$1,169
Rate-regulated natural gas revenues	—	78	—	—	—	78
Shared service and other revenues	—	—	—	113	(109)	4
Total operating revenues	557	384	310	113	(113)	1,251
Three Months Ended March 31, 2017						
Rate-regulated electric revenues	$530	$296	$275	$—	$ (4)	$1,097
Rate-regulated natural gas revenues	—	66	—	—	—	66
Shared service and other revenues	—	—	—	12	—	12
Total operating revenues	530	362	275	12	(4)	1,175
Intersegment revenues:						
Three Months Ended March 31, 2018	$2	$2	$1	$112	$ (113)	$4
Three Months Ended March 31, 2017	1	2	1	13	(5)	12
Net income (loss):						
Three Months Ended March 31, 2018	$31	$31	$7	$(8)	$ 4	$65
Three Months Ended March 31, 2017	58	57	28	(15)	12	140
Total assets:						
March 31, 2018	$7,896	$4,383	$3,530	$10,514	$ (4,948)	$21,375
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 March 31, 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 March 31, 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

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

disaggregation of these tariff sales provided by major customer groups. Exelon's disaggregated revenues are consistent with Generation and the Utility Registrants, but exclude any intercompany revenues.
Competitive Business Revenues (Generation):

	Three Months Ended March 31, 2018				
	Revenues from external parties[(a)]			Intersegment Revenues	Total Revenues
	Contracts with customers	Other[(b)]	Total		
Mid-Atlantic	$1,355	$ 80	$1,435	$ 5	$ 1,440
Midwest	1,273	71	1,344	2	1,346
New England	725	68	793	(1)	792
New York	439	(29)	410	(1)	409
ERCOT	149	59	208	1	209
Other Power Regions	210	109	319	(31)	288
Total Competitive Businesses Electric Revenues	4,151	358	4,509	(25)	4,484
Competitive Businesses Natural Gas Revenues	522	433	955	25	980
Competitive Businesses Other Revenues[(c)]	134	(86)	48	—	48
Total Generation Consolidated Operating Revenues	$4,807	$ 705	$5,512	$ —	$ 5,512

	Three Months Ended March 31, 2017				
	Revenues from external customers[(a)]			Intersegment revenues	Total Revenues
	Contracts with customers	Other[(b)]	Total		
Mid-Atlantic	$1,494	$ (65)	$1,429	$ (4)	$ 1,425
Midwest	980	71	1,051	2	1,053
New England	589	(40)	549	(2)	547
New York	303	(3)	300	(3)	297
ERCOT	168	24	192	(1)	191
Other Power Regions	128	61	189	(5)	184
Total Competitive Businesses Electric Revenues	3,662	48	3,710	(13)	3,697
Competitive Businesses Natural Gas Revenues	768	150	918	12	930
Competitive Businesses Other Revenues[(c)]	206	44	250	1	251
Total Generation Consolidated Operating Revenues	$4,636	$ 242	$4,878	$ —	$ 4,878

(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 $3 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 March 31, 2017, unrealized mark-to-market losses of $98 million and gains of $44 million for the three months ended March 31, 2018 and 2017, respectively, and elimination of intersegment revenues.

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

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

	Three Months Ended March 31, 2018			Three Months Ended March 31, 2017		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$836	$ 14	$850	$755	$ 18	$773
Midwest	847	13	860	704	11	715
New England	122	(3)	119	115	(4)	111
New York	282	1	283	143	—	143
ERCOT	106	(70)	36	94	(25)	69
Other Power Regions	157	(40)	117	108	(44)	64
Total Revenues net of purchased power and fuel expense for Reportable Segments	2,350	(85)	2,265	1,919	(44)	1,875
Other[b]	(131)	85	(46)	161	44	205
Total Generation Revenues net of purchased power and fuel expense	$2,219	$ —	$2,219	$2,080	$ —	$2,080

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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 $3 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the three months ended March 31, 2017, unrealized mark-to-market losses of $266 million and $49 million for the three months ended March 31, 2018 and 2017, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements as discussed in Note 7 - Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements of $15 million decrease to revenue net of purchased power and fuel expense for the three months ended March 31, 2018, 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 (ComEd, PECO, BGE, PHI, PECO, DPL, ACE):

	Three Months Ended March 31, 2018						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$717	$403	$393	$610	$259	$191	$160
Small commercial & industrial	385	101	68	115	32	46	37
Large commercial & industrial	152	58	106	259	190	23	46
Public authorities & electric railroads	14	8	7	14	7	4	3
Other[(a)]	230	62	78	156	49	41	66
Total rate-regulated electric revenues[(b)]	$1,498	$632	$652	$1,154	$537	$305	$312
Rate-regulated natural gas revenues							
Residential	$—	$161	$224	$47	$—	$47	$—
Small commercial & industrial	—	62	34	18	—	18	—
Large commercial & industrial	—	1	47	4	—	4	—
Transportation	—	6	—	5	—	5	—
Other[(c)]	—	2	27	4	—	4	—
Total rate-regulated natural gas revenues[(d)]	$—	$232	$332	$78	$—	$78	$—
Total rate-regulated revenues from contracts with customers	$1,498	$864	$984	$1,232	$537	$383	$312
Other revenues							
Revenues from alternative revenue programs	5	(1)	(13)	18	19	1	(2)
Other rate-regulated electric revenues[(e)]	9	3	4	1	1	—	—
Other rate-regulated natural gas revenues[(e)]	—	—	2	—	—	—	—
Total other revenues	14	2	(7)	19	20	1	(2)
Total rate-regulated revenues for reportable segments	$1,512	$866	$977	$1,251	$557	$384	$310

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

	Three Months Ended March 31, 2017						
Revenues from contracts with customers	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Rate-regulated electric revenues							
Residential	$611	$ 382	$386	$554	$ 236	$176	$142
Small commercial & industrial	328	97	69	114	34	44	36
Large commercial & industrial	107	52	108	257	188	24	45
Public authorities & electric railroads	12	8	7	15	8	4	3
Other[(a)]	218	48	68	126	48	38	43
Total rate-regulated electric revenues[(b)]	$1,276	$ 587	$638	$1,066	$ 514	$286	$269
Rate-regulated natural gas revenues							
Residential	$—	$ 142	$185	$40	$ —	$40	$—
Small commercial & industrial	—	55	30	17	—	17	—
Large commercial & industrial	—	—	44	2	—	2	—
Transportation	—	6	—	5	—	5	—
Other[(c)]	—	3	14	2	—	2	—
Total rate-regulated natural gas revenues[(d)]	$—	$ 206	$273	$66	$ —	$66	$—
Total rate-regulated revenues from contracts with customers	$1,276	$ 793	$911	$1,132	$ 514	$352	$269
Other revenues							
Revenues from alternative revenue programs	14	—	35	30	15	9	6
Other rate-regulated electric revenues[(e)]	8	3	4	2	1	1	—
Other rate-regulated natural gas revenues[(e)]	—	—	1	—	—	—	—
Other revenues[(f)]	—	—	—	11	—	—	—
Total other revenues	22	3	40	43	16	10	6
Total rate-regulated revenues for reportable segments	$1,298	$ 796	$951	$1,175	$ 530	$362	$275

(a) Includes revenues from transmission revenue from PJM, wholesale electric revenue and mutual assistance revenue.
(b) Includes operating revenues from affiliates of $14 million, $2 million, $2 million, $4 million, $2 million, $2 million, and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the three months ended March 31, 2018 and $5 million, $1 million, $2 million, $1 million, $1 million, $2 million, and $1 million at ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, for the three months ended March 31, 2017.
(c) Includes revenues from off-system natural gas sales.
(d) Includes operating revenues from affiliates of less than $1 million and $4 million at PECO and BGE, respectively, for the three months ended March 31, 2018 and less than $1 million and $3 million at PECO and BGE, respectively, for the three months ended March 31, 2017.
(e) Includes late payment charge revenues.
(f) Includes operating revenues from affiliates of $11 million at PHI for the three months ended March 31, 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

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 months ended March 31, 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 March 31, 2018							2017	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI	Other	Exelon	Exelon	Variance
Operating revenues	$5,512	$1,512	$866	$977	$1,251	$(425)	$9,693	$8,747	$ 946
Purchased power and fuel expense	3,293	605	333	380	520	(404)	4,727	3,899	(828)
Revenue net of purchased power and fuel expense[(a)]	2,219	907	533	597	731	(21)	4,966	4,848	118
Other operating expenses									
Operating and maintenance	1,339	313	275	221	309	(73)	2,384	2,438	54
Depreciation and amortization	448	228	75	134	183	23	1,091	896	(195)
Taxes other than income	138	77	41	65	113	12	446	436	(10)
Total other operating expenses	1,925	618	391	420	605	(38)	3,921	3,770	(151)
Gain on sales of assets and businesses	53	3	—	—	—	—	56	4	52
Bargain purchase gain	—	—	—	—	—	—	—	226	(226)
Operating income	347	292	142	177	126	17	1,101	1,308	(207)
Other income and (deductions)									
Interest expense, net	(101)	(89)	(33)	(25)	(63)	(60)	(371)	(373)	2
Other, net	(44)	8	2	4	11	(9)	(28)	257	(285)
Total other income and (deductions)	(145)	(81)	(31)	(21)	(52)	(69)	(399)	(116)	(283)
Income (loss) before income taxes	202	211	111	156	74	(52)	702	1,192	(490)
Income taxes	9	46	(2)	28	9	(31)	59	211	152
Equity in losses of unconsolidated affiliates	(7)	—	—	—	—	—	(7)	(10)	3
Net income	186	165	113	128	65	(21)	636	971	(335)
Net income attributable to noncontrolling interests	50	—	—	—	—	1	51	(19)	(70)
Net income attributable to common shareholders	$136	$165	$113	$128	$65	$(22)	$585	$990	$ (405)

(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.

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Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. Exelon's Net income attributable to common shareholders was $585 million for the three months ended March 31, 2018 as compared to $990 million for the three months ended March 31, 2017, and diluted earnings per average common share were $0.60 for the three months ended March 31, 2018 as compared to $1.06 for the three months ended March 31, 2017.
Revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $118 million for the three months ended March 31, 2018 as compared to the same period in 2017. The quarter-over-quarter increase in Revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase of $390 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 nuclear volumes primarily as a result of the acquisition of FitzPatrick, decreased nuclear outage days, increased capacity prices and the addition of two combined-cycle gas turbines in Texas, partially offset by the conclusion of the Ginna Reliability Support Services Agreement and lower realized energy prices;
- Increase of $44 million at PECO, DPL and ACE primarily due to favorable weather conditions within their respective service territories; and
- Increase of $33 million due to higher mutual assistance revenues across all Utility Registrants, primarily at ComEd.

The quarter-over-quarter increase in Revenue net of purchase power and fuel expense was partially offset by the following unfavorable factors:

- Decrease of $217 million at Generation due to mark-to-market losses of $266 million in 2018 compared to $49 million in 2017; and
- Decrease of $57 million at ComEd primarily due to lower revenues resulting from the change to defer and recover over time energy efficiency costs pursuant to FEJA;
- Decrease of $85 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 earnings due to regulatory rate increases at ComEd, BGE and PHI.

Operating and maintenance expense decreased by $54 million for the three months ended March 31, 2018 as compared to the same period in 2017 primarily due to the following favorable factors:

- Decrease of $57 million at ComEd primarily due to the change to defer and recover over time energy efficiency costs pursuant to FEJA;
- Decrease of $38 million at Generation due to lower merger and integration costs primarily related to the FitzPatrick acquisition;
- Decrease of $33 million at Generation due to lower nuclear refueling outage costs; and
- Decrease of $32 million related to a supplemental NEIL insurance distribution at Generation in the first quarter of 2018.

The quarter-over-quarter decrease in Operating and maintenance expense was partially offset by the following unfavorable factors:

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- Increase of $86 million at PECO and BGE due to increased storm costs;
- Increase of $33 million due to higher mutual assistance expenses across all Utility Registrants, primarily at ComEd; and
- Increase of $22 million at PHI due to uncollectible accounts expense.

Depreciation and amortization expense increased by $195 million primarily due to Generation’s first quarter 2018 decision to early retire the Oyster Creek nuclear facility and Generation’s second quarter 2017 decision to early retire the Three Mile Island nuclear facility, as well increased depreciation expense as a result of ongoing capital expenditures across all operating companies for the three months ended March 31, 2018 as compared to the same period in 2017.

Taxes other than income remained relatively consistent for the three months ended March 31, 2018 as compared to the same period in 2017.

Gain on sales of assets and businesses increased by $52 million for the three months ended March 31, 2018 as compared to the same period in 2017 primarily due to Generation's first quarter 2018 sale of its electrical contracting business.

Bargain purchase gain decreased by $226 million due to the gain associated with the FitzPatrick acquisition in first quarter 2017.

Interest expense, net remained relatively consistent for the three months ended March 31, 2018 as compared to the same period in 2017.

Other, net decreased by $285 million primarily due to net unrealized and realized losses on NDT funds at Generation for the three months ended March 31, 2018 as compared to net unrealized and realized gains on NDT funds for the same period in 2017.

Exelon’s effective income tax rates for the three months ended March 31, 2018 and 2017 were 8.4% and 17.7%, respectively. The decrease in the effective income tax rate for the three months ended March 31, 2018 as 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 further details on TCJA's impact on regulatory proceedings.

For further detail regarding the financial results for the three months ended March 31, 2018, including explanation of the non-GAAP measure Revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

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Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the three months ended March 31, 2018 were $925 million, or $0.96 per diluted share, compared with adjusted (non-GAAP) operating earnings of $600 million, or $0.64 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 months ended March 31, 2018 as compared to the same period in 2017.

(All amounts in millions after tax)	Three Months Ended March 31, 2018	Earnings per Diluted Share	2017	Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$585	$ 0.60	$990	$ 1.06
Mark-to-Market Impact of Economic Hedging Activities[a] (net of taxes of $69 and $19, respectively)	197	0.20	30	0.03
Unrealized Losses (Gains) Related to NDT Fund Investments[b] (net of taxes of $29 and $67, respectively)	66	0.07	(99)	(0.10)
Amortization of Commodity Contract Intangibles[c] (net of taxes of $0 and $2, respectively)	—	—	3	—
Merger and Integration Costs[d] (net of taxes of $1 and $15, respectively)	3	—	25	0.03
Merger Commitments[e] (net of taxes of $0 and $137, respectively)	—	—	(137)	(0.15)
Plant Retirements and Divestitures[f] (net of taxes of $32 and $0, respectively)	92	0.10	—	—
Cost Management Program[g] (net of taxes of $1 and $3, respectively)	5	0.01	4	—
Bargain Purchase Gain[h] (net of taxes of $0)	—	—	(226)	(0.24)
Reassessment of State Deferred Income Taxes[i] (entire amount represents tax expense)	—	—	(20)	(0.02)
Tax Settlements[j] (net of taxes of $0 and $1, respectively)	—	—	(5)	(0.01)
Noncontrolling Interests[k] (net of taxes of $5 and $7, respectively)	(23)	(0.02)	35	0.04
Adjusted (non-GAAP) Operating Earnings	$925	$ 0.96	$600	$ 0.64

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 differing rates for investments if they are in qualified or non-qualified funds. The tax rates applied to unrealized gains and losses related to NDT fund investments were 40.3 percent and 52.6 percent for the three months ended March 31, 2018 and 2017, respectively.

(a) Reflects the impact of net gains and losses on Generation's economic hedging activities. See Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of net unrealized gains and losses on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

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

(d) 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

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in 2018. See Note 4 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.

(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 accelerated depreciation and amortization expenses and increases to materials and supplies inventory reserves associated with Generation’s 2018 decision to early retire the Oyster Creek nuclear facility, as well as the accelerated depreciation and amortization expense associated with Generation’s 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

(g) Represents severance and reorganization costs related to a cost management program.

(h) Represents the excess fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

(i) Reflects the change in the District of Columbia statutory tax rate.

(j) Reflects benefits related to the favorable settlement in 2017 of certain income tax positions related to PHI’s unregulated business interests.

(k) Represents 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.

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 $500 million in ongoing annual savings to be returned to customers related to TCJA from their distribution utility operations.

ComEd and BGE have received orders approving the pass back of the ongoing annual tax savings of $201 million and $103 million, respectively, beginning February 1, 2018. DPL received an order from the MDPSC approving the pass back of $14 million of ongoing annual tax savings beginning April 20, 2018 and a one-time bill credit to customers of $2 million for TCJA tax savings from January 1, 2018 through March 31, 2018. Pepco has entered into settlement agreements with parties in both Maryland and the District of Columbia providing for the pass back of the ongoing annual tax savings beginning June 1, 2018 and July 1, 2018, respectively, and one-time bill credits to customers for TCJA tax savings from January 1, 2018 through the effective date of the rate changes. PECO’s, DPL Delaware’s and ACE’s filings are still pending and management cannot predict the amount or timing of the refunds their respective regulators will ultimately approve. For PECO, BGE, DPL Delaware and ACE, it is expected that the treatment of the TCJA tax savings through the effective date of any final customer rate adjustments will be addressed in future rate proceedings.

In addition, ComEd, BGE, 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. PECO is currently in settlement discussions regarding its transmission formula rate and expects to pass back TCJA benefits to customers through its annual formula rate update. PECO, BGE, Pepco, DPL and ACE recognized new regulatory liabilities in the first quarter 2018 reflecting the TCJA tax savings that are anticipated to be passed back to customers in the future. See Note 6 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further 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 by October 2018. 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.

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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 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.

	Actual	Projected[(a)]	
Income statement expense (pre-tax)	Q1 2018	2018	2019
Depreciation and amortization[(b)]			
Accelerated depreciation[(c)]	$ 137	$550	$330
Accelerated nuclear fuel amortization	15	55	5
Operating and maintenance[(d)]	26	26	—
Total	$ 178	$631	$335

(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 for the quarter ended March 31, 2018, and Oyster Creek from February 2, 2018 through March 31, 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.

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 recently announced that it would take a three-step approach to fuel security. First, ISO-NE will make a filing soon to obtain tariff waivers to allow it to retain Mystic 8 and 9 for fuel security for the 2022 - 2024 planning years. Second, ISO-NE will 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 will 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. 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. 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. Refer to 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. In the first quarter of 2018, Generation recognized approximately $202 million of revenue, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

New Jersey Zero Emission Certificate Program

On April 12, 2018, a bill was passed by both Houses of the New Jersey legislature that would 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. The program provides transparency and includes robust customer protections. The New Jersey Governor has up to 45 days to sign the bill, with the bill becoming effective immediately upon signing. The NJBPU then 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. Exelon and Generation continue to work with stakeholders.

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. Closing of the transaction is expected to occur in the third quarter of 2018. Exelon has 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 has reached an agreement with Brookfield that all Exelon contracts will be assumed by Brookfield on the closing date. Closing of the transaction is subject to numerous conditions, including regulatory approvals.

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 information on other regulatory proceedings.

Completed Distribution Base Rate Case Proceedings

Company	Jurisdiction	Approved Revenue Requirement Increase (Decrease) (in millions)	Approved Return on Equity	Completion Date	Rate Effective Date
DPL	Maryland (Electric)	$ 13	9.5 %	February 9, 2018	February 9, 2018

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Pending Distribution Base Rate Case Proceedings

Company	Jurisdiction	Requested Revenue Requirement Increase (Decrease) (in millions)		Requested Return on Equity		Filing Date	Expected Completion Timing
ComEd	Illinois (Electric)	$	(23)	8.69	%	April 16, 2018	Fourth quarter 2018
PECO	Pennsylvania (Electric)	$	82	10.95	%	March 29, 2018	Fourth quarter 2018
Pepco	Maryland (Electric)	$	(15)	9.5	%	January 2, 2018 (Updated February 5, 2018, March 8, 2018 and April 20, 2018)	Second quarter 2018
Pepco	District of Columbia (Electric)	$	(24)	9.525	%	December 19, 2017 (Updated on February 9, 2018 and April 17, 2018)	Second quarter 2018
DPL	Delaware (Electric)	$	12	10.1	%	August 17, 2017 (Updated on October 18, 2017 and February 9, 2018)	Third quarter 2018
DPL	Delaware (Natural Gas)	$	4	10.1	%	August 17, 2017 (Updated on November 7, 2017 and February 9, 2018)	Fourth quarter 2018

See Note 6 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these base rate case proceedings.

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 are presented below:

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	(in millions)		
	Customer Outages	Incremental Operating & Maintenance	Incremental Capital Expenditures
Exelon	1,724,000	$ 93 [b]	$ 93
PECO	750,000	56	36
BGE	425,000	31	18
PHI[a]	549,000	6 [b]	39
Pepco	179,000	3 [b]	6
DPL	138,000	3 [b]	5
ACE	232,000	— [b]	28

(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 $22 million, $22 million, $5 million, $1 million and $16 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 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

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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, of which approximately 60% of run-rate savings was achieved by the end of 2017 with the remainder to be fully realized in 2018. At least 75% of the savings are expected to be related to Generation, with the remaining amount related to the Utility Registrants. Additionally, in November 2017, Exelon announced a new commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. 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 $26 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.

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.

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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. See Liquidity and Capital Resources - Credit Matters - Exelon Credit Facilities below.

For further detail regarding the Registrants' liquidity for the three months ended March 31, 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.

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).

DOE Notice of Proposed Rulemaking

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. The DOE's NOPR recommended that the FERC take comments for 45 days after publication in the Federal Register and issue a final order 60-days after such publication. On January 8, 2018, the FERC issued an order terminating the rulemaking docket that was 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, the 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. The FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Interested parties may submit reply comments through May 9, 2018. 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.

PJM Minimum Offer Price Rule Expanded and Repricing Filing

On April 9, 2018, PJM filed a request at FERC seeking approval of its proposed capacity repricing mechanism or, in the alternative, the Minimum Offer Price Rule Expanded (MOPREx) proposal. PJM argues that both proposed approaches are just and reasonable means of resolving the conflict between state policy support for certain resources and the need to provide reasonable prices for non-supported resources because both prevent state-supported resources from suppressing market clearing prices. PJM expresses a preference for the repricing approach as it "honors the state's legitimate policy choice to promote resources with certain attributes not otherwise valued in the current wholesale market rules; MOPREx does not. Thus, PJM asks FERC to sequentially consider the two proposals; first considering the repricing approach and then considering the MOPREx approach only if FERC cannot accept repricing. The MOPREx alternative, if selected by FERC, could impact Exelon and Generation as this mechanism could undermine the benefit of Illinois' ZEC program and similar programs that could be developed in other states. Specifically, under PJM's MOPREx alternative, the MOPR mitigation mechanism would apply to all resources (not just new resources, as is currently done) including ZEC-supported resources, thereby mitigating the effect of state support in offers and rendering it unlikely that ZEC-supported resources will clear the capacity auction. While numerous exceptions would be available under MOPREx, none would be available to ZEC programs. PJM asks for a FERC order by June 29, 2018 and an effective date of June 30, 2018. It is too early to predict the final outcome or its 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. The relief sought by the petitioners would require U.S. nuclear reactors to purchase at least 25% of their uranium needs from domestic mines over the next 10 years. If the DOC initiates an investigation, 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 petition. It is reasonably possible that if this

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petition were 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.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in flat to declining load growth in electricity for the Utility Registrants. There is an increase in projected load for electricity for PECO, BGE, Pepco and ACE, and a decrease in projected load for electricity at ComEd and DPL. ComEd, PECO, BGE, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by (0.1)%, 0.3%, 1.1%, 2.1%, (1.9)% and 2.9% 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. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, 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 is payable on June 8, 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 March 31, 2018, the percentage of expected generation hedged is 91%-94%, 63%-66% and 33%-36% 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 58% 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.

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 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 have been specifically identified for review are 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 2015 National Ambient Air Quality Standard (NAAQS) for ozone. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

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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 indicated its intent to issue 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.

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. EPA did not meet the October 1, 2017 deadline to promulgate initial designations for areas in attainment or non-attainment of the standard. A number of states and environmental organizations have notified the EPA of their intent to file suit to compel EPA to issue the designations.

Climate Change. Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of Federal legislation, the EPA is moving forward with 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, "Water Quality" of the Exelon 2017 Form 10-K for further discussion.

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, Mountain Creek, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS, "Water Quality" for further discussion.

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 classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded accruals consistent with state regulation for its owned coal ash sites, and as such, the regulation 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 new federal regulations 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 further detail related to environmental matters, including the impact of environmental regulation.

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. Additionally, prior to commencing negotiations at Braidwood Generating Station with its Security Union, SPFPA Local 228, a rival Union petitioned the NLRB to represent the Security Officers in lieu of the incumbent Union. An election was held and the incumbent Union prevailed. The rival union sought to overturn the election and filed unfair labor practice charges against the incumbent which were denied following an NLRB Regional Hearing. Due to the legal proceedings between the Unions, the existing CBA was extended prior to the NLRB hearing and currently expires in August 2018. Lastly, negotiations for a collective bargaining agreement with Local 501 of Operating Engineers are ongoing with a small unit of employees at Exelon's Hyperion Solutions facility.

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

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 more 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

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Comprehensive Income include both: (i) the recognition of "originating" ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the "originating" ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, 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 further 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 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 March 31, 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 March 31, 2018	2017	Favorable (Unfavorable) Variance
Exelon	$585	$990	$ (405)
Generation	136	418	(282)
ComEd	165	141	24
PECO	113	127	(14)
BGE	128	125	3
PHI	65	140	(75)
Pepco	31	58	(27)
DPL	31	57	(26)
ACE	7	28	(21)

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Results of Operations — Generation

	Three Months Ended March 31, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$5,512	$4,878	$ 634
Purchased power and fuel expense	3,293	2,798	(495)
Revenues net of purchased power and fuel expense[(a)]	2,219	2,080	139
Other operating expenses			
Operating and maintenance	1,339	1,492	153
Depreciation and amortization	448	302	(146)
Taxes other than income	138	143	5
Total other operating expenses	1,925	1,937	12
Gain on sales of assets and businesses	53	4	49
Bargain purchase gain	—	226	(226)
Operating income	347	373	(26)
Other income and (deductions)			
Interest expense, net	(101)	(100)	(1)
Other, net	(44)	259	(303)
Total other income and (deductions)	(145)	159	(304)
Income before income taxes	202	532	(330)
Income taxes	9	123	114
Equity in losses of unconsolidated affiliates	(7)	(10)	3
Net income	186	399	(213)
Net income (loss) attributable to noncontrolling interests	50	(19)	(69)
Net income attributable to membership interest	$136	$418	$ (282)

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. Generation's Net income attributable to membership interest for the three months ended March 31, 2018 decreased compared to the same period in 2017, primarily due to higher Depreciation and amortization expenses, a Bargain purchase gain in 2017, and lower Other income, partially offset by higher Revenue net of purchased power and fuel expense, lower Operating and maintenance expenses, higher Gain on sales of assets and businesses and lower Income taxes. The increase in Depreciation and amortization is primarily due to accelerated depreciation and amortization expenses associated with Generation's first quarter 2018 decision to early retire the Oyster Creek nuclear facility and Generation's second quarter 2017 decision to early retire TMI. The Bargain purchase gain is due to the acquisition of the FitzPatrick nuclear facility in 2017. The decrease in Other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. The increase in Revenue net of purchased power and fuel expense primarily relates to the impacts of the New York CES and Illinois Zero Emission Standards (including the impact of zero emission credits generated in Illinois from June 1, 2017 through

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December 31, 2017), the acquisition of the FitzPatrick nuclear facility and decreased nuclear outage days, and higher capacity prices, partially offset by increased Mark-to-market losses in 2018 compared to 2017, the conclusion of the Ginna Reliability Support Services Agreement and lower realized energy prices, partially offset by the addition of two combined-cycle gas turbines in Texas. The decrease in Operating and maintenance is primarily due to certain costs associated with mergers and acquisitions related to the PHI and FitzPatrick acquisitions, decreased nuclear outage days in 2018, and the impact of a supplemental NEIL distribution, partially offset by increased operating expenses related to the 2017 acquisition of FitzPatrick. The increase in Gain on sales of assets and businesses is primarily due Generation's 2018 sale of its electrical contracting business. The decrease in income taxes is primarily due to tax savings related to TCJA.

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, 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.

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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.
For the three months ended March 31, 2018 and 2017, Generation's Revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended March 31,		Variance	% Change
	2018	2017		
Mid-Atlantic[a]	$850	$773	$ 77	10.0 %
Midwest[b]	860	715	145	20.3 %
New England	119	111	8	7.2 %
New York[d]	283	143	140	97.9 %
ERCOT	36	69	(33)	(47.8)%
Other Power Regions	117	64	53	82.8 %
Total electric revenue net of purchased power and fuel expense	2,265	1,875	390	20.8 %
Proprietary Trading	6	—	6	— %
Mark-to-market losses	(266)	(49)	(217)	442.9 %
Other[c]	214	254	(40)	(15.7)%
Total revenue net of purchased power and fuel expense	$2,219	$2,080	$ 139	6.7 %

(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 $3 million decrease to revenue net of purchased power and fuel expense for the three months ended March 31, 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 $15 million decrease to revenue net of purchased power and fuel expense for the three months ended March 31, 2018.
(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 March 31, 2018	2017	Variance	% Change
Nuclear generation				
Mid-Atlantic[(a)]	16,229	16,545	(316)	(1.9)%
Midwest	23,597	22,468	1,129	5.0 %
New York[(a)(c)]	7,115	4,491	2,624	58.4 %
Total Nuclear Generation	46,941	43,504	3,437	7.9 %
Fossil and Renewables				
Mid-Atlantic	900	836	64	7.7 %
Midwest	455	418	37	8.9 %
New England	2,035	2,077	(42)	(2.0)%
New York	1	1	—	— %
ERCOT	2,949	1,370	1,579	115.3 %
Other Power Regions	1,993	1,423	570	40.1 %
Total Fossil and Renewables	8,333	6,125	2,208	36.0 %
Purchased Power				
Mid-Atlantic	766	3,398	(2,632)	(77.5)%
Midwest	336	388	(52)	(13.4)%
New England	5,436	5,064	372	7.3 %
New York	—	28	(28)	— %
ERCOT	1,373	2,655	(1,282)	(48.3)%
Other Power Regions	4,134	2,868	1,266	44.1 %
Total Purchased Power	12,045	14,401	(2,356)	(16.4)%
Total Supply/Sales by Region				
Mid-Atlantic[(b)]	17,895	20,779	(2,884)	(13.9)%
Midwest[(b)]	24,388	23,274	1,114	4.8 %
New England	7,471	7,141	330	4.6 %
New York	7,116	4,520	2,596	57.4 %
ERCOT	4,322	4,025	297	7.4 %
Other Power Regions	6,127	4,291	1,836	42.8 %
Total Supply/Sales by Region	67,319	64,030	3,289	5.1 %

(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.

Mid-Atlantic

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $77 million increase in Revenue net of purchased power and fuel expense in the Mid-Atlantic primarily

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reflects higher realized energy prices and increased capacity prices, partially offset by increased nuclear outage days.

Midwest

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $145 million increase in Revenue net of purchased power and fuel expense in the Midwest was primarily due to the impact of the Illinois Zero Emission Standard (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017) and decreased nuclear outage days, partially offset by lower realized energy prices.

New England

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $8 million increase in Revenue net of purchased power and fuel expense in New England primarily reflects increased capacity prices, partially offset by lower realized energy prices.

New York

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $140 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 and lower realized energy prices.

ERCOT

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $33 million decrease in Revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices, partially offset by the addition of two combined-cycle gas turbines in Texas.

Other Power Regions

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $53 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 March 31, 2018 Compared to Three Months Ended March 31, 2017. The $6 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 March 31, 2018 Compared to Three Months Ended March 31, 2017. Mark-to-market losses on economic hedging activities were $266 million for the three months ended March 31, 2018 compared to losses of $49 million for the three months ended March 31, 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 information on gains and losses associated with mark-to-market derivatives.

Other

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The $40 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 and higher 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 higher natural gas portfolio optimization.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for the three months ended March 31, 2018 as 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 March 31,	
	2018	2017
Nuclear fleet capacity factor[(a)]	96.5%	94.0%
Refueling outage days[(a)]	68	95
Non-refueling outage days[(a)]	6	8

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. The nuclear fleet capacity factor increased primarily due to fewer non-refueling and refueling outage days, excluding Salem outages, during the three months ended March 31, 2018 compared to the same period in 2017.

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Operating and Maintenance Expense

The changes in Operating and maintenance expense for the three months ended March 31, 2018 as compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, Increase (Decrease)[(a)]
Labor, other benefits, contracting, materials[(b)]	$ (51)
Nuclear refueling outage costs, including the co-owned Salem plants[(c)]	(33)
Corporate allocations	8
Insurance[(d)]	(32)
Merger and integration costs[(e)]	(38)
Plant retirements and divestitures[(f)]	26
Other	(33)
Decrease in Operating and maintenance expense	$ (153)

(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.

(c) Primarily reflects a decrease in the number of nuclear outage days for the three months ended March 31, 2018 compared to 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 accelerated depreciation and amortization expenses and increases to materials and supplies inventory reserves associated with Generation’s 2018 decision to early retire the Oyster Creek nuclear facility, as well as the accelerated depreciation and amortization expense associated with Generation’s 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.

Depreciation and Amortization Expense

Depreciation and amortization expense for the three months ended March 31, 2018 compared to the same period in 2017 increased primarily due to accelerated depreciation and amortization expenses associated with Generation's first quarter 2018 decision to early retire the Oyster Creek nuclear facility and Generation's second quarter 2017 decision to early retire TMI.

Taxes Other Than Income

Taxes other than income taxes, 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 months ended March 31, 2018 compared to the same period in 2017 remained relatively stable.

Gain on Sales of Assets and Businesses

Gain on sales of assets and businesses for the three months ended March 31, 2018 compared to the same period in 2017 increased primarily due to Generation's 2018 sale of its electrical contracting business.

Bargain Purchase Gain

Bargain purchase gain for the three months ended March 31, 2018 compared to the same period in 2017 decreased as a result of the gain associated with the FitzPatrick acquisition in 2017. Refer to Note 4 — Mergers, Acquisitions and

Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

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Interest Expense, Net

Interest expense, net for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively stable.

Other, Net

Other, net for the three months ended March 31, 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 $(7) million and $56 million for the three months ended March 31, 2018 and 2017, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 13 — Nuclear Decommissioning 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 months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
Net unrealized (losses) gains on decommissioning trust funds	$(96)	$166
Net realized gains on sale of decommissioning trust funds	28	9

Equity in Losses of Unconsolidated Affiliates

Equity in losses of unconsolidated affiliates for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively stable.

Effective Income Tax Rate

Generation's effective income tax rate was 4.5% and 23.1% for the three months ended March 31, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended March 31, 2018 as 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. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

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Results of Operations — ComEd

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017	Favorable (Unfavorable) Variance
Operating revenues	$1,512	$1,298	$ 214
Purchased power expense	605	334	(271)
Revenues net of purchased power expense[(a)(b)]	907	964	(57)
Other operating expenses			
Operating and maintenance	313	370	57
Depreciation and amortization	228	208	(20)
Taxes other than income	77	72	(5)
Total other operating expenses	618	650	32
Gain on sales of assets	3	—	3
Operating income	292	314	(22)
Other income and (deductions)			
Interest expense, net	(89)	(85)	(4)
Other, net	8	4	4
Total other income and (deductions)	(81)	(81)	—
Income before income taxes	211	233	(22)
Income taxes	46	92	46
Net income	$165	$141	$ 24

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. ComEd's Net income for the three months ended March 31, 2018 was higher than the same period in 2017 primarily due to higher electric distribution, transmission and energy efficiency formula rate earnings. The TCJA did not impact ComEd's net income for the three months ended March 31, 2018 as the favorable income tax impacts were fully 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.

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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 months ended March 31, 2018 and 2017, consisted of the following:

	Three Months Ended March 31, 2018	2017
Electric	69 %	71 %

Retail customers purchasing electric generation from competitive electric generation suppliers at March 31, 2018 and 2017 consisted of the following:

	March 31, 2018 Number of customers	% of total retail customers	March 31, 2017 Number of customers	% of total retail customers
Electric	1,360,000	34 %	1,453,000	36 %

The changes in ComEd's Revenue net of purchased power expense for the three months ended March 31, 2018, compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, Increase (Decrease)
Electric distribution revenue	$ (31)
Transmission revenue	(6)
Energy efficiency revenue[(a)]	8
Regulatory required programs[(a)]	(57)
Uncollectible accounts recovery, net	1
Other	28
Total decrease	$ (57)

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(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.

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.

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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 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 months ended March 31, 2018 and 2017, consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended March 31,	2018	2017	Normal	2018 vs. 2017	2017 vs. Normal
Heating Degree-Days	3,117	2,650	3,141	17.6%	(0.8)%
Cooling Degree-Days	—	—	—	n/a	n/a

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 months ended March 31, 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 March 31, 2018, ComEd recorded decreased transmission revenue primarily due to the decreased peak load, 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 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

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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 three months ended March 31, 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 March 31, 2018	2017	Increase (Decrease)
Operating and maintenance expense — baseline	$313	$313	$ —
Operating and maintenance expense — regulatory required programs[(a)]	—	57	(57)
Total operating and maintenance expense	$313	$370	$ (57)

(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 months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials[(a)]	$ 9
Pension and non-pension postretirement benefits expense[(a)]	1
Storm-related costs	(6)
Uncollectible accounts expense — provision[(b)]	2
Uncollectible accounts expense — recovery, net[(b)]	(1)
BSC costs[(a)]	(3)
Other[(a)]	(2)
	—
Regulatory required programs	
Energy efficiency and demand response programs[(c)]	(57)
Decrease in operating and maintenance expense	$ (57)

(a) Includes additional costs associated with mutual assistance programs. An equal and offsetting decrease 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 months ended March 31, 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 decrease has been recognized in Operating revenues for the period presented.

(c) 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.

Depreciation and Amortization Expense

The increase in Depreciation and amortization expense during the three months ended March 31, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 11
Regulatory asset amortization[(b)]	9
Total increase	$ 20

(a) Primarily reflects ongoing capital expenditures for the three months ended March 31, 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. Taxes other than income taxes remained relatively consistent for the three months ended March 31, 2018, compared to the same period in 2017.

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Gain on Sales of Assets

The increase in Gain on sales of assets during the three months ended March 31, 2018, compared to the same period in 2017, is due to the sale of land during March 2018.

Interest Expense, Net

Interest expense, net, remained relatively consistent for the three months ended March 31, 2018, compared to the same period in 2017.

Other, Net

Other, net, remained relatively consistent for the three months ended March 31, 2018, compared to the same period in 2017.

Effective Income Tax Rate

ComEd's effective income tax rate was 21.8% and 39.5% for the three months ended March 31, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended March 31, 2018 as 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.

ComEd Electric Operating Statistics Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2018	2017	% Change	Weather-Normal % Change
Retail Deliveries[a]				
Residential	6,614	6,241	6.0 %	1.0 %
Small commercial & industrial	7,843	7,709	1.7 %	(0.5)%
Large commercial & industrial	6,837	6,683	2.3 %	0.7 %
Public authorities & electric railroads	362	344	5.2 %	2.8 %
Total retail deliveries	21,656	20,977	3.2 %	0.4 %

Number of Electric Customers	As of March 31, 2018	2017
Residential	3,633,369	3,605,498
Small commercial & industrial	379,255	375,617
Large commercial & industrial	1,980	2,000
Public authorities & electric railroads	4,781	4,818
Total	4,019,385	3,987,933

(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 March 31, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$866	$796	$ 70
Purchased power and fuel expense	333	287	(46)
Revenues net of purchased power and fuel expense[(a)]	533	509	24
Other operating expenses			
Operating and maintenance	275	208	(67)
Depreciation and amortization	75	71	(4)
Taxes other than income	41	38	(3)
Total other operating expenses	391	317	(74)
Operating income	142	192	(50)
Other income and (deductions)			
Interest expense, net	(33)	(31)	(2)
Other, net	2	2	—
Total other income and (deductions)	(31)	(29)	(2)
Income before income taxes	111	163	(52)
Income taxes	(2)	36	38
Net income	$113	$127	$ (14)

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. PECO's Net income decreased from the same period in 2017, primarily due to higher Operating and maintenance expense attributable to increased storm restoration costs as a result of winter storms in March 2018, partially offset by higher Operating revenues net of purchase power and fuel expense attributable to favorable weather. The TCJA did not impact PECO's Net income for the three months ended March 31, 2018 as the favorable income tax impacts were fully offset by lower revenues resulting from the pass back of 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 specifies 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.

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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 months ended March 31, 2018 and 2017, consisted of the following:

	Three Months Ended March 31,	
	2018	2017
Electric	67%	70%
Natural Gas	25%	25%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at March 31, 2018 and 2017 consisted of the following:

	March 31, 2018		March 31, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	557,700	34 %	589,700	36 %
Natural Gas	83,800	16 %	81,300	16 %

The changes in PECO’s Operating revenues net of purchased power and fuel expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)		
	Electric	Natural Gas	Total
Weather	$17	$ 12	$29
Volume	—	3	3
Pricing	(7)	(6)	(13)
Regulatory required programs	(2)	—	(2)
Other	9	(2)	7
Total increase	$17	$ 7	$24

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as “favorable weather conditions” because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2018 compared to the same period in 2017, Operating revenue net of purchased power and fuel increased due to favorable weather conditions.

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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 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three months ended March 31, 2018 compared to the same periods in 2017 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended March 31,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	2,418	2,094	2,444	15.5%	(1.1)%
Cooling Degree-Days	—	—	1	— %	(100.0)%

Volume. Operating revenue net of purchased power related to delivery volume, exclusive of the effects of weather, for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent. Operating revenue net of fuel expense for the three months ended March 31, 2018 compared to the same period in 2017 increased due to strong customer growth and moderate economic growth.

Pricing. Operating revenues net of purchased power as a result of pricing for the three months ended March 31, 2018 compared to the same period in 2017 decreased primarily due to the pass back through customers rates the tax savings associated with 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 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. Refer to the 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 March 31,		Increase (Decrease)
	2018	2017	
Operating and maintenance expense — baseline	$259	$196	$ 63
Operating and maintenance expense — regulatory required programs[(a)]	16	12	4
Total operating and maintenance expense	$275	$208	$ 67

(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 months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	$ 5
Storm-related costs[(a)]	59
Pension and non-pension postretirement benefits expense	(2)
Other	1
	63
Regulatory Required Programs	
Energy efficiency	4
Total increase	$ 67

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(a) Reflects increased costs incurred from the Q1 2018 winter storms.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense increased primarily due to ongoing capital spend for the three months ended March 31, 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 months ended March 31, 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 months ended March 31, 2018 remained relatively consistent compared to the same period in 2017.

Other, Net

Other, net for the three months ended March 31, 2018 remained consistent compared to the same period in 2017.

Effective Income Tax Rate

PECO's effective income tax rate was (1.8)% and 22.1% for the three months ended March 31, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended March 31, 2018 as 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 March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]				
Residential	3,628	3,378	7.4 %	0.1 %
Small commercial & industrial	2,029	1,976	2.7 %	(1.0)%
Large commercial & industrial	3,703	3,626	2.1 %	2.0 %
Public authorities & electric railroads	197	224	(12.1)%	(12.1)%
Total retail deliveries	9,557	9,204	3.8 %	0.3 %

Number of Electric Customers	As of March 31, 2018	2017
Residential	1,474,555	1,461,662
Small commercial & industrial	151,947	150,580
Large commercial & industrial	3,113	3,100
Public authorities & electric railroads	9,541	9,798
Total	1,639,156	1,625,140

(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.

PECO Natural Gas Operating Statistics

Deliveries to Customers (in mmcf)	Three Months Ended March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]				
Residential	20,574	18,112	13.6 %	0.9 %
Small commercial & industrial	10,417	9,091	14.6 %	2.8 %
Large commercial & industrial	47	8	487.5 %	460.6 %
Transportation	7,568	7,689	(1.6)%	(7.8)%
Total natural gas deliveries	38,606	34,900	10.6 %	(0.3)%

Number of Natural Gas Customers	As of March 31, 2018	2017
Residential	478,565	473,972
Small commercial & industrial	44,053	43,705
Large commercial & industrial	4	4
Transportation	768	775
Total	523,390	518,456

(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 March 31, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$977	$951	$ 26
Purchased power and fuel expense	380	350	(30)
Revenues net of purchased power and fuel expense[(a)]	597	601	(4)
Other operating expenses			
Operating and maintenance	221	183	(38)
Depreciation and amortization	134	128	(6)
Taxes other than income	65	62	(3)
Total other operating expenses	420	373	(47)
Operating income	177	228	(51)
Other income and (deductions)			
Interest expense, net	(25)	(27)	2
Other, net	4	4	—
Total other income and (deductions)	(21)	(23)	2
Income before income taxes	156	205	(49)
Income taxes	28	80	52
Net income	$128	$125	$ 3

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. BGE’s Net income for the three months ended March 31, 2018 was higher than the same period in 2017, primarily due to higher transmission revenues, which were partially offset by an increase in Operating and maintenance expense attributable to increased storm restoration costs as a result of winter storms in March 2018. The TCJA did not impact BGE's net income for the three months ended March 31, 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 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.

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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 months ended March 31, 2018 and 2017 consisted of the following:

	Three Months Ended March 31, 2018	2017
Electric	57%	58%
Natural Gas	46%	48%

The number of retail customers purchasing electricity and natural gas from competitive suppliers at March 31, 2018 and 2017 consisted of the following:

	March 31, 2018		March 31, 2017	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	340,900	26 %	339,600	27 %
Natural Gas	150,200	22 %	149,300	22 %

The changes in BGE’s Operating revenues net of purchased power and fuel expense for the three months ended March 31, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)		
	Electric	Gas	Total
Distribution revenue	$(19)	$(14)	$(33)
Regulatory required programs	3	3	6
Transmission revenue	13	—	13
Other, net	5	5	10
Total increase (decrease)	$2	$(6)	$(4)

Distribution Revenue. The decrease in distribution revenues for the three months ended March 31, 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.

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

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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 months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended March 31,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	2,440	2,063	2,391	18.3%	2.0 %
Cooling Degree-Days	—	—	—	n/a	n/a

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 months ended March 31, 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 late payment fees and other miscellaneous revenue such as service application fees, assistance provided to other utilities through BGE's mutual assistance program and recoveries of electric supply and natural gas procurement costs.

Operating and Maintenance Expense

	Three Months Ended March 31,		Increase (Decrease)
	2018	2017	
Operating and maintenance expense — baseline	$207	$167	$ 40
Operating and maintenance expense — regulatory required programs[(a)]	14	16	(2)
Total operating and maintenance expense	$221	$183	$ 38

(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 months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Baseline	
Storm-related costs[a]	$ 27
Labor, other benefits, contracting and materials	4
Uncollectible accounts expense	3
BSC costs	3
Other	3
	40
Regulatory Required Programs	
Other	(2)
Total increase	$ 38

(a) Reflects increased storm restoration costs incurred from the Q1 2018 winter storms.

Depreciation and Amortization

The changes in Depreciation and amortization expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Depreciation expense[a]	$ 1
Regulatory asset amortization[b]	(3)
Regulatory required programs[c]	8
Total increase	$ 6

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

(b) Regulatory asset amortization decreased for the three months ended March 31, 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.

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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 months ended March 31, 2018, compared to the same period in 2017, remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three months ended March 31, 2018, compared to the same period in 2017, remained relatively consistent.

Other, Net

Other, net for the three months ended March 31, 2018, compared to the same period in 2017, remained relatively consistent.

Effective Income Tax Rate

BGE's effective income tax rate was 17.9% and 39.0% for the three months ended March 31, 2018 and 2017, respectively. The decrease in the effective income tax rate for the three months ended March 31, 2018 as 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.

BGE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]				
Residential	3,580	3,127	14.5 %	3.7 %
Small commercial & industrial	784	748	4.8 %	2.2 %
Large commercial & industrial	3,356	3,268	2.7 %	0.1 %
Public authorities & electric railroads	67	68	(1.5)%	8.4 %
Total electric deliveries	7,787	7,211	8.0 %	2.0 %

Number of Electric Customers	As of March 31, 2018	2017
Residential	1,163,887	1,153,688
Small commercial & industrial	113,675	113,238
Large commercial & industrial	12,148	12,084
Public authorities & electric railroads	270	279
Total	1,289,980	1,279,289

(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 March 31, 2018	2017	% Change		Weather - Normal % Change	
Retail Deliveries[a]						
Residential	21,775	18,117	20.2	%	1.8	%
Small commercial & industrial	4,774	3,778	26.4	%	6.7	%
Large commercial & industrial	15,650	14,476	8.1	%	1.0	%
Other[b]	5,378	2,279	136.0	%	n/a	
Total natural gas deliveries	47,577	38,650	23.1	%	2.0	%

Number of Gas Customers	As of March 31, 2018	2017
Residential	631,594	625,642
Small commercial & industrial	38,443	37,913
Large commercial & industrial	5,874	6,324
Total	675,911	669,879

(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 5,378 mmcfs and 2,279 mmcfs for the three months ended March 31, 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 March 31,		Favorable (Unfavorable)
	2018	2017	Variance
Operating revenues	$1,251	$1,175	$ 76
Purchased power and fuel expense	520	461	(59)
Revenues net of purchased power and fuel expense[(a)]	731	714	17
Other operating expenses			
Operating and maintenance	309	256	(53)
Depreciation and amortization	183	167	(16)
Taxes other than income	113	111	(2)
Total other operating expenses	605	534	(71)
Operating income	126	180	(54)
Other income and (deductions)			
Interest expense, net	(63)	(62)	(1)
Other, net	11	13	(2)
Total other income and (deductions)	(52)	(49)	(3)
Income before income taxes	74	131	(57)
Income taxes	9	(9)	(18)
Net income	$65	$140	$ (75)

(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.

Net Income

Three Months Ended March 31, 2018 Compared to Three Months Ended March 31, 2017. PHI's Net income for the three months ended March 31, 2018 was $65 million compared to $140 million for of three months ended March 31, 2017. The decrease in Net income reflects an increase in Operating and maintenance expense and an increase in the Depreciation and amortization expense partially offset by the impact of increases in electric distribution base rates and natural gas rates within Revenues net of purchased power and fuel expense. The TCJA did not impact PHI’s Net income for the three months ended March 31, 2018 as the favorable income tax impacts were fully 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 revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $17 million for the three months ended March 31, 2018 compared to the same period in 2017. The increase is primarily attributable to the following factors:

- Increase of $11 million at Pepco primarily related to the impact of the new electric distribution base rates charged to customers in Maryland that became effective in October 2017, the impact of new electric distribution base rates charged to customers in the District of Columbia effective August 2017, and the impact of an increase in the Maryland surcharge rate (which is substantially offset in Taxes other than income), partially offset by the impact of reduced distribution rates to reflect the lower federal income tax rate;
- Increase of $11 million at ACE primarily related to higher average residential and commercial customer usage, favorable weather related sales, and the impact of the new electric distribution base rate charged to customers that became effective in October 2017, partially offset by the impact of reduced distribution rates to reflect the lower federal income tax rate;
- Increase of $2 million at DPL primarily related to favorable weather related sales, partially offset by the impact of reduced distribution base rates to reflect the lower federal income tax rate; and
- Decrease of $8 million at PHI Corporate primarily related to lower affiliate revenues at PHISCO as a result of the completion of integration transition activities.

Operating and Maintenance Expense

Operating and maintenance expense increased by $53 million for the three months ended March 31, 2018 compared to the same period in 2017. The increase is attributable to the following factors:

- Increase of $25 million at DPL primarily due to a write-off of construction work-in-progress, higher uncollectible accounts expense as a result of higher accounts receivable, and the absence of integration cost deferrals from 2017;
- Increase of $17 million at Pepco primarily due to higher uncollectible accounts expense as a result of higher accounts receivable;
- Increase of $14 million at ACE primarily due to an increase in labor and contracting expense; and
- Decrease of $5 million at PHI Corporate primarily related to lower labor expense at PHISCO as a result of the completion of integration transition activities.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $16 million primarily due to ongoing capital expenditures at Pepco, DPL, and ACE.

Taxes Other Than Income

Taxes other than income for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent.

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Other, Net

Other, net for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent.

Effective Income Tax Rate

PHI's effective income tax rate was 12.2% and (6.9)% for the three months ended March 31, 2018 and 2017, respectively. The increase in the effective income tax rate for the three months ended March 31, 2018 as compared to the same period in 2017 is primarily due to the absence of unrecognized tax benefits for Pepco, DPL, and ACE from 2017, partially offset by 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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Results of Operations - Pepco

	Three Months Ended March 31, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$557	$530	$ 27
Purchased power expense	182	166	(16)
Revenues net of purchased power expense[(a)]	375	364	11
Other operating expenses			
Operating and maintenance	130	113	(17)
Depreciation and amortization	96	82	(14)
Taxes other than income	93	90	(3)
Total other operating expenses	319	285	(34)
Operating income	56	79	(23)
Other income and (deductions)			
Interest expense, net	(31)	(29)	(2)
Other, net	8	8	—
Total other income and (deductions)	(23)	(21)	(2)
Income before income taxes	33	58	(25)
Income taxes	2	—	(2)
Net income	$31	$58	$ (27)

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. Pepco's Net income for the three months ended March 31, 2018, was lower than the same period in 2017, primarily due to higher Operating and maintenance expense attributable to an increase in Uncollectible accounts expense as a result of higher accounts receivable and higher Depreciation and amortization expense attributable to ongoing capital expenditures, partially offset by higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and higher electric distribution base rates charged to customers in the District of Columbia that became effective August 2017. The TCJA did not impact Pepco's Net income for the three months ended March 31, 2018 as the favorable tax impacts were fully 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,

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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 months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018	2017
Electric	62%	64%

Retail customers purchasing electric generation from competitive electric generation suppliers at March 31, 2018 and 2017 consisted of the following:

	March 31, 2018		March 31, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	178,859	20%	179,241	21%

Retail deliveries purchased from competitive electric generation suppliers represented 71% of Pepco's retail kWh sales to the District of Columbia customers and 56% of Pepco's retail kWh sales to Maryland customers for the three months ended March 31, 2018, respectively and 73% of Pepco's retail kWh sales to the District of Columbia customers and 58% of Pepco's retail kWh sales to Maryland customers for the three months ended March 31, 2017, respectively.

The changes in Pepco's operating revenues net of purchased power expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Volume	$ 3
Distribution revenue	(1)
Regulatory required programs	14
Transmission revenues	(4)
Other	(1)
Total increase	$ 11

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 months ended March 31, 2018 compared to the same period in 2017, primarily reflects the impact of residential customer growth.

Distribution Revenue. The decrease in distribution revenues for the three months ended March 31, 2018 compared to the same period in 2017 was primarily due to the impact of reduced distribution

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rates to reflect the lower federal income tax rate partially offset by higher electric distribution base rates charged to customers in Maryland that became effective in October 2017 and higher electric distribution base rates charged to customers in the District of Columbia that became effective August 2017. See Note 6—Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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 months ended March 31, 2018 compared to the same period in 2017 and normal weather consisted of the following:

				% Change	
Three Months Ended March 31,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	2,129	1,748	2,129	21.8 %	— %
Cooling Degree-Days	4	4	3	— %	33.3 %

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. Refer to the 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 months ended March 31, 2018, compared to the same period in 2017, due to increases in the Maryland and District of Columbia surcharge rates and sales due to higher volumes (which are substantially offset in Taxes other than income and Depreciation and amortization expense).

Transmission Revenues. 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 revenues for the three months ended March 31, 2018 compared to the same period in 2017 is a result of a decrease in network transmission service peak loads.

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.

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Operating and Maintenance Expense

	Three Months Ended March 31, 2018	2017	Increase (Decrease)
Operating and maintenance expense - baseline	$ 132	$ 114	$ 18
Operating and maintenance expense - regulatory required programs[a]	(2)	(1)	(1)
Total operating and maintenance expense	$ 130	$ 113	$ 17

(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 months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Baseline	
Uncollectible accounts expense	11
Labor and contracting	2
BSC and PHISCO costs	3
Other	2
	18
Regulatory required programs	
Purchased power administrative costs	(1)
Total increase	$ 17

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Depreciation expense[a]	$ 3
Regulatory asset amortization[b]	8
Regulatory required programs[c]	3
Total increase	$ 14

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

(b)

Regulatory asset amortization increased for the three months ended March 31, 2018 compared to the same period in 2017, primarily due to higher amortization of DC PLUG regulatory asset. An equal and offsetting amount has been reflected in Operating revenues.

(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 and Operating and maintenance expense.

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Taxes Other Than Income

Taxes other than income for the three months ended March 31, 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).

Interest Expense, Net

Interest expense, net for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent.

Other, Net

Other, net for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively consistent.

Effective Income Tax Rate

Pepco's effective income tax rate was 6.1% and 0.0% for the three months ended March 31, 2018 and 2017, respectively. The increase in the effective income tax rate for the three months ended March 31, 2018 as compared to the same period in 2017 is primarily due to the absence of an unrecognized tax benefit from 2017, partially offset by 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 change in effective income tax rates.

Pepco Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]				
Residential	2,283	2,000	14.2 %	3.5 %
Small commercial & industrial	346	326	6.1 %	1.8 %
Large commercial & industrial	3,670	3,485	5.3 %	3.3 %
Public authorities & electric railroads	176	190	(7.4)%	(7.9)%
Total retail deliveries	6,475	6,001	7.9 %	3.0 %

Number of Electric Customers	As of March 31, 2018	2017
Residential	797,105	785,016
Small commercial & industrial	53,602	53,640
Large commercial & industrial	21,718	21,413
Public authorities & electric railroads	146	136
Total	872,571	860,205

(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 March 31, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$384	$362	$ 22
Purchased power and fuel expense	177	157	(20)
Revenues net of purchased power and fuel expense[(a)]	207	205	2
Other operating expenses			
Operating and maintenance	98	73	(25)
Depreciation and amortization	45	39	(6)
Taxes other than income	15	15	—
Total other operating expenses	158	127	(31)
Operating income	49	78	(29)
Other income and (deductions)			
Interest expense, net	(13)	(13)	—
Other, net	2	3	(1)
Total other income and (deductions)	(11)	(10)	(1)
Income before income taxes	38	68	(30)
Income taxes	7	11	4
Net income	$31	$57	$ (26)

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. DPL's Net income for the three months ended March 31, 2018, was lower than the same period in 2017 primarily due to higher Operating and maintenance expense attributable to an increase in Uncollectible accounts expense as a result of higher accounts receivable, an absence of integration cost deferrals from 2017 and a write-off of construction work in progress. The TCJA did not impact DPL's Net income for the three months ended March 31, 2018 as the favorable tax impacts were fully offset by lower revenues resulting from the pass back of the tax savings through customer rates.

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

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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 months ended March 31, 2018 and 2017, consisted of the following:

	Three Months Ended March 31,	
	2018	2017
Electric	46%	50%
Natural Gas	24%	27%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at March 31, 2018 and 2017 consisted of the following:

	March 31, 2018		March 31, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	75,280	14.4 %	79,270	15.2 %
Natural Gas	155	0.1 %	156	0.1 %

Retail deliveries purchased from competitive electric generation suppliers represented 48% of DPL’s retail kWh sales to Delaware customers and 41% of DPL's retail kWh sales to Maryland customers for the three months ended March 31, 2018, respectively and 53% of DPL's retail kWh sales to Delaware customers and 45% of DPL's retail kWh sales to Maryland customers for the three months ended March 31, 2017, respectively.

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The changes in DPL’s Operating revenues net of purchased power and fuel expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)		
	Electric	Gas	Total
Weather	$5	$7	$12
Volume	2	(1)	1
Distribution revenue	(8)	(5)	(13)
Transmission revenues	1	—	1
Other	1	—	1
Total increase	$1	$1	$2

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 months ended March 31, 2018 compared to the same period in 2017, operating revenue net of purchased power and fuel expense was higher due to the impact of favorable weather conditions in DPL'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 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 months ended March 31, 2018 compared to the same period in 2017 and normal weather consisted of the following:

Electric Service Territory				% Change	
Three Months Ended March 31,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	2,415	2,094	2,407	15.3 %	0.3 %
Cooling Degree-Days	1	—	2	100.0%	(50.0)%

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Natural Gas Service Territory				% Change	
Three Months Ended March 31,	2018	2017	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	2,504	2,171	2,502	15.3%	0.1 %

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 months ended March 31, 2018 compared to the same period in 2017, primarily reflects the impact of increased average residential and commercial customer usage.

Distribution Revenue. The decrease in distribution revenues for the three months ended March 31, 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.

Transmission Revenues. 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 transmission revenues for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively consistent.

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 March 31,		Increase (Decrease)
	2018	2017	
Operating and maintenance expense - baseline	$97	$ 72	$ 25
Operating and maintenance expense - regulatory required programs[(a)]	1	1	—
Total operating and maintenance expense	$98	$ 73	$ 25

(a) Reflects accumulated integration costs that were deferred as regulatory assets in 2017.

The changes in Operating and maintenance expense for the three months ended March 31, 2018 compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Baseline	
Uncollectible accounts expense	8
Write-off of construction work in progress	7
Merger commitments[(a)]	8
Other	2
Total increase	$ 25

(a) Reflects an absence of integration cost deferrals from 2017.

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Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 2
Regulatory asset amortization	4
Total increase	$ 6

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

Taxes Other Than Income

Taxes other than income for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively consistent.

Other, Net

Other, net for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively consistent.

Effective Income Tax Rate

DPL's effective income tax rate was 18.4% and 16.2% for the three months ended March 31, 2018 and 2017, respectively. The increase in the effective income tax rate for the three months ended March 31, 2018 as compared to the same period in 2017 is primarily due to the absence of an unrecognized tax benefit from 2017, partially offset by 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.

DPL Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]				
Residential	1,551	1,359	14.1 %	3.5 %
Small commercial & industrial	569	531	7.2 %	3.8 %
Large commercial & industrial	1,079	1,064	1.4 %	(0.2)%
Public authorities & electric railroads	12	13	(7.7)%	(7.7)%
Total retail deliveries	3,211	2,967	8.2 %	2.2 %

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Number of Electric Customers	As of March 31, 2018	2017
Residential	460,863	457,663
Small commercial & industrial	60,962	60,289
Large commercial & industrial	1,383	1,411
Public authorities & electric railroads	625	642
Total	523,833	520,005

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

DPL Natural Gas Operating Statistics and Detail

Retail Deliveries to Customers (in mmcf)	Three Months Ended March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[(a)]				
Residential	4,485	3,741	19.9 %	3.6 %
Small commercial & industrial	1,878	1,686	11.4 %	(5.0)%
Large commercial & industrial	516	505	2.2 %	2.2 %
Transportation	2,213	2,168	2.1 %	(2.0)%
Total natural gas deliveries	9,092	8,100	12.2 %	0.3 %

Number of Gas Customers	As of March 31, 2018	2017
Residential	123,062	121,362
Small commercial & industrial	9,873	9,837
Large commercial & industrial	17	18
Transportation	155	156
Total	133,107	131,373

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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 March 31, 2018	2017	Favorable (Unfavorable) Variance
Operating revenues	$310	$275	$ 35
Purchased power expense	161	137	(24)
Revenues net of purchased power expense[(a)]	149	138	11
Other operating expenses			
Operating and maintenance	90	76	(14)
Depreciation and amortization	33	35	2
Taxes other than income	3	2	(1)
Total other operating expenses	126	113	(13)
Operating income	23	25	(2)
Other income and (deductions)			
Interest expense, net	(16)	(15)	(1)
Other, net	1	2	(1)
Total other income and (deductions)	(15)	(13)	(2)
Income before income taxes	8	12	(4)
Income taxes	1	(16)	(17)
Net income	$7	$28	$ (21)

(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 March 31, 2018 Compared to Three Months Ended March 31, 2017. ACE's Net income for the three months ended March 31, 2018, was lower than the same period in 2017, primarily due to higher Income tax expense as a result of a decrease in unrecognized tax liabilities during 2017 and an increase in Operating and maintenance expenses attributable to higher labor and contracting expenses, partially offset by an increase in Revenues net of purchased power expense resulting from higher distribution revenues due to higher average residential and commercial customer usage, favorable weather related sales, and the impact of electric distribution base rate increases approved by the NJBPU effective October 2017. The TCJA did not impact ACE's Net income for the three months ended March 31, 2018 as the favorable income tax impacts were fully 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 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

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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 months ended March 31, 2018, compared to the same period in 2017, consisted of the following:

	Three Months Ended March 31, 2018	2017
Electric	47 %	49 %

Retail customers purchasing electric generation from competitive electric generation suppliers at March 31, 2018 and 2017 consisted of the following:

	March 31, 2018		March 31, 2017	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	85,462	15 %	93,896	17 %

The changes in ACE’s operating revenue net of purchased power expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Weather	$ 3
Volume	7
Distribution revenue	3
Regulatory required programs	(2)
Transmission revenues	(1)
Other	1
Total increase	$ 11

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 months ended March 31, 2018 compared to the same period in 2017, operating revenue net of purchased power and fuel expense 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 months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

				% Change	
Three Months Ended March 31,	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	2,413	2,150	2,474	12.2%	(2.5)%
Cooling Degree-Days	—	—	1	—%	(100.0)%

Volume. During the three months ended March 31, 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 customer usage.
Distribution Revenue. The increase in distribution revenue for the three months ended March 31, 2018, compared to the same period in 2017, was primarily due to higher electric distribution base rates charged to customers that became effective in October 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. Revenue from regulatory required programs decreased for the three months ended March 31, 2018, compared to the same period in 2017, due to a rate decrease effective October 2017 for the ACE Transition Bonds.
Transmission Revenues. 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 transmission revenue net of purchased power expense remained relatively consistent for the three months ended March 31, 2018 compared to the same period in 2017.
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.

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Operating and Maintenance Expense

	Three Months Ended March 31, 2018	2017	Increase (Decrease)
Operating and maintenance expense - baseline	$87	$ 75	$ 12
Operating and maintenance expense - regulatory required programs[(a)]	3	1	2
Total operating and maintenance expense	$90	$ 76	$ 14

(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 months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Baseline	
Labor and contracting	$ 9
Uncollectible accounts expense[(a)]	3
	12
Regulatory required programs	
Purchased power administrative costs	2
Total increase	$ 14

(a) The uncollectible accounts expense is offset in Operating revenues.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for the three months ended March 31, 2018 compared to the same period in 2017 consisted of the following:

	Three Months Ended March 31, 2018 Increase (Decrease)
Depreciation expense[(a)]	$ 1
Regulatory asset amortization	1
Regulatory required programs[(b)]	(4)
Total decrease	$ (2)

(a) Depreciation expense increased due to ongoing capital expenditures.
Regulatory required programs decreased for the three months ended March 31, 2018 compared to the same period in 2017 as a result of lower revenue due to rate decreases effective October 2017 for the ACE Transition Bonds.

(b) 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 and Operating and maintenance expense.

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Taxes Other Than Income
Taxes other than income for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent.
Interest Expense, Net
Interest expense, net for the three months ended March 31, 2018 compared to the same period in 2017 remained relatively consistent.
Other, Net
Other, net for the three months ended March 31, 2018 compared to the same period in 2017, remained relatively consistent.
Effective Income Tax Rate
ACE's effective income tax rate was 12.5% and (133.3)% for the three months ended March 31, 2018 and 2017, respectively. The increase in the effective income tax rate for the three months ended March 31, 2018 as compared to the same period in 2017 is primarily due to the absence of an unrecognized tax benefit from 2017, partially offset by 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.
ACE Electric Operating Statistics and Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31, 2018	2017	% Change	Weather - Normal % Change
Retail Deliveries[a]				
Residential	990	879	12.6 %	7.4 %
Small commercial & industrial	314	283	11.0 %	9.0 %
Large commercial & industrial	824	765	7.7 %	6.9 %
Public authorities & electric railroads	15	13	15.4 %	15.4 %
Total retail deliveries	2,143	1,940	10.5 %	7.5 %

Number of Electric Customers	As of March 31, 2018	2017
Residential	488,495	485,691
Small commercial & industrial	61,059	60,999
Large commercial & industrial	3,611	3,761
Public authorities & electric railroads	643	612
Total	553,808	551,063

(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 December 2019. 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 further discussion. 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 further discussion 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 — Nuclear Decommissioning 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 Exelon to post parental guarantees for Generation's share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, 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 — Nuclear Decommissioning 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 March 31, 2018, across the alternative 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 $235 million and $205 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 $90 million net of taxes.

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 further discussion 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 three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,		
	2018	2017	Variance
Net income	$636	$971	$ (335)
Add (subtract):			
Non-cash operating activities[a]	1,998	1,229	769
Pension and non-pension postretirement benefit contributions	(331)	(307)	(24)
Income taxes	86	50	36
Changes in working capital and other noncurrent assets and liabilities[b]	(646)	(753)	107
Option premiums received (paid), net	(27)	(6)	(21)
Collateral (posted) received, net	(214)	(110)	(104)
Net cash flows provided by operations	$1,502	$1,074	$ 428

(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 and other non-cash charges. See Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further detail 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).

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.

On October 3, 2017, the US 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.

The EMA requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF's disposition of a majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the investment in CENG.

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

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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. Refer to Note 3 - 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, rate regulators could require the passing back of amounts to customers over shorter time frames, which could materially decrease operating cash outflows at each of the Utility Registrants in the near term.

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 continue to work with their state regulatory commissions to determine the amount and timing of the passing back of TCJA income tax savings benefits to customers; with filings either made, or expected to be made, at PECO, Pepco, DPL Delaware and ACE, and approved filings at ComEd, BGE and DPL Maryland. The amounts being passed back or proposed to be passed back to customers reflect the benefit of lower income tax expense beginning January 1, 2018 (February 1, 2018 for DPL Delaware), and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. Refer to Note 3 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on their filings.

In general, most states use federal taxable income as the starting point for computing state corporate income tax. Now that the TCJA has been enacted, state governments are beginning to analyze the impact of the TCJA on their state revenues. Exelon is uncertain regarding what the state governments will do, and there is a possibility that state corporate income taxes could change due to the enactment of the TCJA. In 2018, Exelon will be closely monitoring the states' responses to the TCJA as these could have an impact on Exelon's future cash flows.

See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Information for further information on the amounts of the net regulatory liabilities subject to determinations by rate regulators.

- 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 three months ended March 31, 2018 and 2017 by Registrant were as follows:

	Three Months Ended March 31,	
	2018	2017
Exelon	$1,502	$1,074
Generation	855	420
ComEd	134	236
PECO	19	106
BGE	313	208
PHI	279	194
Pepco	126	29
DPL	115	122
ACE	59	58

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

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normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the three months ended March 31, 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 three months ended March 31, 2018 and 2017, Generation had net payments of counterparty cash collateral of $214 million and $102 million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.
- During the three months ended March 31, 2018 and 2017, Generation had net payments of approximately $27 million and $6 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.

ComEd

- During each of the three months ended March 31, 2018 and 2017, ComEd posted approximately $8 million of cash collateral with PJM, respectively. As of March 31, 2018 and 2017, ComEd had approximately $59 million and $32 million cash collateral posted with PJM, respectively. ComEd's total collateral posted with PJM has increased year over year primarily due to an increase in ComEd's RPM credit requirements and peak market activity with PJM.

For further discussion regarding changes in non-cash operating activities, please refer to Note 18 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Investing Activities

Cash flows used in investing activities for the three months ended March 31, 2018 and 2017 by Registrant were as follows:

	Three Months Ended March 31,	
	2018	2017
Exelon	$(1,857)	$(2,283)
Generation	(615)	(910)
ComEd	(523)	(619)
PECO	(215)	(69)
BGE	(223)	(202)
PHI	(258)	(323)
Pepco	(127)	(144)
DPL	(65)	(80)
ACE	(64)	(87)

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Significant investing cash flow impacts for the Registrants for three months ended March 31, 2018 and 2017 were as follows:

Exelon and Generation

- During the three months ended March 31, 2018, Exelon had proceeds of $79 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 three months ended March 31, 2017, Exelon had expenditures of $23 million and $182 million relating to the acquisitions of ConEdison Solutions and the FitzPatrick facility, respectively.

Capital Expenditure Spending

Generation

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 three months ended March 31, 2018 and 2017 and projected amounts for the full year 2018 are as follows:

	Projected Full Year 2018[(a)]	Three Months Ended March 31,	
		2018	2017
Exelon[(b)]	$ 7,875	$1,880	$2,009
Generation	2,075	628	625
ComEd[(c)]	2,125	531	626
PECO	850	217	201
BGE	1,000	224	206
PHI[(d)]	1,525	258	320
Pepco	725	127	139
DPL	400	65	82
ACE	400	63	88

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(a) Total projected capital expenditures do not include adjustments for non-cash activity.

(b) Includes corporate operations, BSC, and PHISCO rounded to the nearest $25 million.

(c) The capital expenditures and 2018 projections include approximately $86 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 rounded to the nearest $25 million.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 39% and 11% 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,

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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 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. BGE, Pepco, DPL and ACE have substantially completed their assessments 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 three months ended March 31, 2018 and 2017 by Registrant were as follows:

	Three Months Ended March 31,	
	2018	2017
Exelon	$264	$1,184
Generation	(57)	582
ComEd	407	359
PECO	(53)	(72)
BGE	(84)	1
PHI	(13)	66
Pepco	9	114
DPL	(45)	(44)
ACE	11	(20)

Debt

See Note 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances.

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Dividends

Cash dividend payments and distributions during the three months ended March 31, 2018 and 2017 by Registrant were as follows:

	Three Months Ended March 31, 2018	2017
Exelon	$333	$303
Generation	188	164
ComEd	114	105
PECO	287	72
BGE	52	49
PHI	71	69
Pepco	25	30
DPL	36	30
ACE	9	10

Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2018 and for the second 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

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(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 three months ended March 31, 2018 and 2017 by Registrant were as follows:

	Three Months Ended March 31, 2018	2017
Exelon	$726	$781
Generation	165	18
ComEd	317	365
PECO	220	—
BGE	(32)	50
PHI	57	(355)
Pepco	34	144
DPL	(5)	—
ACE	28	—

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Contributions from Parent/Member

Contributions received from Parent/Member for the three months ended March 31, 2018 and 2017 by Registrant were as follows:

	Three Months Ended March 31,	
	2018	2017
ComEd[(a)(b)]	$113	$100
PHI[(b)]	—	500

(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.

Other

For the three months ended March 31, 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 further details 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 March 31, 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 first 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 further 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 March 31, 2018, it would have been required to provide incremental collateral of $1.9 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 March 31, 2018 and available credit facility capacity prior to any incremental collateral at March 31, 2018:

	PJM Credit Policy Collateral	Other Incremental Collateral Required(a)	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 10	$ —	$ 998
PECO	3	33	599
BGE	10	49	597
Pepco	10	—	299
DPL	4	14	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 March 31, 2018:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size(a)(b)	Outstanding Commercial Paper at March 31, 2018	Average Interest Rate on Commercial Paper Borrowings for the Three Months Ended March 31, 2018
Exelon Corporate	$ 600	$ —	1.85 %
Generation	5,300	165	1.93 %
ComEd	1,000	317	1.91 %
PECO	600	220	2.08 %
BGE	600	45	1.86 %
Pepco	500	60	2.01 %
DPL	500	211	1.88 %
ACE	350	136	1.90 %

(a) Excludes $545 million bilateral credit facilities that do not back Generation's commercial paper program.

(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities' service territories. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of March 31, 2018, letters of credit issued under these agreements for Generation and BGE totaled $5 million and $2 million, respectively.

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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 March 31, 2018, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Borrower	Facility Type	Aggregate Bank Commitment[(a)(b)(c)]	Facility Draws	Outstanding Letters of Credit[(c)]	Available Capacity at March 31, 2018	
					Actual	To Support Additional Commercial Paper[(b)(d)]
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 45	$ 555	$ 555
Generation	Syndicated Revolver	5,300	—	1,121	4,179	4,014
Generation	Bilaterals	545	—	338	207	—
ComEd	Syndicated Revolver	1,000	—	2	998	681
PECO	Syndicated Revolver	600	—	1	599	379
BGE	Syndicated Revolver	600	—	3	597	552
Pepco	Syndicated Revolver	300	—	1	299	239
DPL	Syndicated Revolver	300	—	—	300	89
ACE	Syndicated Revolver	300	—	—	300	164

(a) Excludes $128 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. These facilities expire on October 12, 2018. These facilities are solely utilized to issue letters of credit. As of March 31, 2018, letters of credit issued under these agreements for Generation and BGE totaled $5 million and $2 million, respectively.

(b) 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 maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility

(c) Excludes nonrecourse debt letters of credit, see Note 13 — Debt and Credit Agreements in the Exelon 2017 Form 10-K for further information.

(d) Excludes $545 million bilateral credit facilities that do not back Generation's commercial paper program.

As of March 31, 2018, there were no borrowings under Generation's bilateral credit facilities.

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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

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 three months ended March 31, 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 March 31, 2018, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	6.83	13.07	11.37	8.28	10.21	6.24	8.48	5.65

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.

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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.

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 March 31, 2018, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended March 31, 2018		As of March 31, 2018
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 551	$ —	$ 494
Generation	38	(389)	(54)
PECO	285	(233)	(194)
BSC	—	(403)	(288)
PHI Corporate	—	(35)	(13)
PCI	55	—	54

PHI Intercompany Money Pool	During the Three Months Ended March 31, 2018		As of March 31, 2018
Contributed (Borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 28	$ —	$ 4
PHISCO	10	(18)	1

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 —Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further 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

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other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

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:

	Short-term Financing Authority[a]			Long-term Financing Authority[a]		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount
ComEd[b]	FERC	December 31, 2019	$ 2,500	ICC	2019	$ 583
PECO	FERC	December 31, 2019	1,500	PAPUC	December 31, 2018	950
BGE	FERC	December 31, 2019	700	MDPSC	N/A	700
Pepco	FERC	December 31, 2019	500	MDPSC / DCPSC	December 31, 2020	600
DPL	FERC	December 31, 2019	500	MDPSC / DPSC	December 31, 2020	350
ACE	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 $143 million available in new money long term debt financing authority from the ICC as of March 31, 2018 and has an expiration date of June 1, 2019 and March 1, 2019, respectively. On April 9, 2018, ComEd filed an application for $1.5 billion in new money long-term debt financing authority from the ICC and expects approval by August 1, 2018.

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 further 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 March 31, 2018, the percentage of expected generation hedged is 91%-94%, 63%-66% and 33%-36% 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 March 31, 2018 market conditions and hedged position would be an decrease in pre-tax net income of approximately $44 million, $336 million and $608 million, respectively, for 2018, 2019 and 2020. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs 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.

Proprietary Trading Activities

Proprietary trading portfolio activity for the three months ended March 31, 2018 resulted in $6 million of pre-tax gains due to net mark-to-market gains of $2 million and realized gains of $4 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 58% 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 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. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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

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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. For additional information on these contracts, see Note 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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).

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 March 31, 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 March 31, 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	14	14	—	—	—
Reclassification to realized of contracts recorded in results of operations	(279)	(279)	—	—	—
Contracts received at acquisition date	—	—	—	—	—
Changes in fair value — recorded through regulatory assets and liabilities[(b)]	(10)	—	(11)	1	1
Changes in allocated collateral	217	218	—	(1)	(1)
Changes in net option premium paid/(received)	27	27	—	—	—
Option premium amortization	7	7	—	—	—
Upfront payments and amortizations[(c)]	(30)	(30)	—	—	—
Total mark-to-market energy contract net assets (liabilities) at March 31, 2018[(a)]	$ 613	$ 880	$ (267)	$ —	$ —

(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 March 31, 2018, ComEd recorded a regulatory liability of $267 million related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the three months ended March 31, 2018, ComEd also recorded $17 million of decreases in fair value and an increase for realized losses due to settlements of $6 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

(c) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortization.

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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.

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)	$(37)	$(15)	$8	$2	$—	$(49)
Prices provided by external sources (Level 2)	(5)	(11)	23	4	—	—	11
Prices based on model or other valuation methods (Level 3)[c]	442	314	51	(13)	(53)	(90)	651
Total	$430	$266	$59	$(1)	$(51)	$(90)	$613

(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 $684 million at March 31, 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)	$(37)	$(15)	$8	$2	$—	$(49)
Prices provided by external sources (Level 2)	(5)	(11)	23	4	—	—	11
Prices based on model or other valuation methods (Level 3)	460	337	73	9	(31)	70	918
Total	$448	$289	$81	$21	$(29)	$70	$880

(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 $684 million at March 31, 2018.

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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)	$(18)	$(23)	$(22)	$(22)	$(22)	$(160)	$(267)

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

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 a detailed discussion 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 March 31, 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 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 $31 million, $21 million, $25 million, $34 million, $9 million and $5 million as of March 31, 2018, respectively.

Rating as of March 31, 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	$ 986	$ 1	$ 985	2	$ 412
Non-investment grade	112	46	66		
No external ratings					
Internally rated — investment grade	223	—	223		
Internally rated — non-investment grade	100	17	83		
Total	$ 1,421	$ 64	$ 1,357	2	$ 412

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Rating as of March 31, 2018	Maturity of Credit Risk Exposure Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$894	$ 92	$ —	$ 986
Non-investment grade	104	8	—	112
No external ratings				
Internally rated — investment grade	161	32	30	223
Internally rated — non-investment grade	93	7	—	100
Total	$1,252	$ 139	$ 30	$ 1,421

Net Credit Exposure by Type of Counterparty	As of March 31, 2018
Financial institutions	$ 189
Investor-owned utilities, marketers, power producers	656
Energy cooperatives and municipalities	438
Other	74
Total	$ 1,357

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(a) As of March 31, 2018, credit collateral held from counterparties where Generation had credit exposure included $41 million of cash and $23 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 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 information regarding collateral requirements. See Note 17 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for 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 March 31, 2018, ComEd held approximately $9 million in collateral from suppliers in association with energy procurement contracts, approximately $14 million in collateral from suppliers for REC and ZEC contract obligations and approximately $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 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 fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At March 31, 2018, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $636 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and interest rate hedges are 100% effective, a hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 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 March 31, 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 investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $652 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 further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the first 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 March 31, 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.

Beginning January 1, 2018, the Registrants adopted the Revenue from Contracts with Customers standard. Although the guidance had an immaterial impact on 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, they did perform implementation controls, including contract reviews, to adopt the new standard, and implemented certain changes to their ongoing revenue recognition processes and control activities, which included enhancements to contract review and valuation processes, new training, and gathering of information for disclosures.

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With the exception of the above, there have been no changes in internal control over financial reporting that occurred during the first 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 March 31, 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.

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.

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Exhibit No.	Description
4.1	Supplemental Indenture dated as of February 6, 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 February 20, 2018, Exhibit 4.1)
4.2	One Hundred and Fifteenth Supplemental Indenture dated as of February 1, 2018 from PECO Energy Company to U.S. Bank National Association, as trustee (File No. 000-16844, Form 8-K dated February 23, 2018, Exhibit 4.1)
4.3	One Hundred and Twentieth Supplemental Indenture, dated April 3, 2018, between DPL and The Bank of New York Mellon, as trustee.
10.1	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective November 1, 2015) * Filed herewith.
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 March 31, 2018 filed by the following officers for the following companies:

31-1 — Filed by Christopher M. Crane for Exelon Corporation

31-2 — Filed by Jonathan W. Thayer 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 Anne R. Pramaggiore for Commonwealth Edison Company

31-6 — Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company

31-7 — Filed by Michael A. Innocenzo for PECO Energy Company

31-8 — Filed by Phillip S. Barnett 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 Donna J. Kinzel for Pepco Holdings LLC

31-13— Filed by David M. Velazquez for Potomac Electric Power Company

31-14— Filed by Donna J. Kinzel for Potomac Electric Power Company

31-15— Filed by David M. Velazquez for Delmarva Power & Light Company

31-16— Filed by Donna J. Kinzel for Delmarva Power & Light Company

31-17— Filed by David M. Velazquez for Atlantic City Electric Company

31-18— Filed by Donna J. Kinzel 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 March 31, 2018 filed by the following officers for the following companies:

32-1 — Filed by Christopher M. Crane for Exelon Corporation

32-2 — Filed by Jonathan W. Thayer 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 Anne R. Pramaggiore for Commonwealth Edison Company

32-6 — Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company

32-7 — Filed by Michael A. Innocenzo for PECO Energy Company

32-8 — Filed by Phillip S. Barnett 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 Donna J. Kinzel for Pepco Holdings LLC

32-13— Filed by David M. Velazquez for Potomac Electric Power Company

32-14— Filed by Donna J. Kinzel for Potomac Electric Power Company

32-15— Filed by David M. Velazquez for Delmarva Power & Light Company

32-16— Filed by Donna J. Kinzel for Delmarva Power & Light Company

32-17— Filed by David M. Velazquez for Atlantic City Electric Company

32-18— Filed by Donna J. Kinzel 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
Christopher M. Crane

President and Chief Executive Officer
(Principal Executive Officer) and Director

/s/ JONATHAN W. THAYER
Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

/s/ FABIAN E. SOUZA
Fabian E. Souza
Senior Vice President and Corporate Controller
(Principal Accounting Officer)
May 2, 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)
May 2, 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/ ANNE R. PRAMAGGIORE	/s/ JOSEPH R. TRPIK, JR.
Anne R. Pramaggiore	Joseph R. Trpik, Jr.
President and 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)
May 2, 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/ PHILLIP S. BARNETT
Michael A. Innocenzo	Phillip S. Barnett
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)
May 2, 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
(Principal Executive Officer)	Officer)

/s/ ANDREW W. HOLMES
Andrew W. Holmes
Vice President and Controller
(Principal Accounting Officer)
May 2, 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/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
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)
May 2, 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/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
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)
May 2, 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/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
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)
May 2, 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/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
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)
May 2, 2018