EXELON CORP
Form 10-Q
August 02, 2017
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended June 30, 2017

or

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

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
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	36-0938600

	(312) 394-4321	
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	PEPCO HOLDINGS LLC (a Delaware limited liability company) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation) 701 Ninth Street, N.W. Washington, District of Columbia 20068 (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

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

Indicate by check mark whether the registrant has submitted electronically 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 No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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					
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					

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

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

The number of shares outstanding of each registrant s common stock as of June 30, 2017 was:

Exelon Corporation Common Stock, without par value	960,087,898
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,160
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, $.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
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
BSC	Exelon Business Services Company, LLC
PHISCO	PHI Service Company
Exelon Corporate	Exelon in its corporate capacity as a holding company
PHI Corporate	PHI in its corporate capacity as a holding company
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
AmerGen	AmerGen Energy Company, LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo 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.
EGTP	ExGen Texas Power, LLC
EGR	ExGen Renewables I, LLC
Entergy	Entergy Nuclear FitzPatrick, LLC
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
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.
Ventures	Exelon Ventures Company, LLC

Other Terms and Abbreviations	
Note of the Exelon 2016 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon s 2016 Annual Report on Form 10-K
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AMI	Advanced Metering Infrastructure
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
BGS	Basic Generation Service
Block Contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
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
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
DC PLUG	District of Columbia Power Line Undergrounding
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
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDCs	Electric distribution companies
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

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
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
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
HSR Act	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
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
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
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
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
PURTA	Pennsylvania Public Realty Tax Act
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
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
UGSOA	United Government Security Officers of America
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 2016 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 24, 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 June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Competitive businesses revenues	$ 3,908	$ 3,234	$ 8,468	$ 7,708
Rate-regulated utility revenues	3,715	3,676	7,913	6,777
Total operating revenues	7,623	6,910	16,381	14,485
Operating expenses				
Competitive businesses purchased power and fuel	2,158	1,576	4,952	4,016
Rate-regulated utility purchased power and fuel	928	878	2,033	1,692
Operating and maintenance	2,971	2,505	5,431	5,341
Depreciation and amortization	915	941	1,811	1,626
Taxes other than income	420	394	857	720
Total operating expenses	7,392	6,294	15,084	13,395
Gain on sales of assets	1	31	5	40
Bargain purchase gain			226	
Operating income	232	647	1,528	1,130
Other income and (deductions)				
Interest expense, net	(426)	(366)	(789)	(643)
Interest expense to affiliates	(10)	(10)	(20)	(20)
Other, net	205	144	488	258
Total other income and (deductions)	(231)	(232)	(321)	(405)
Income before income taxes	1	415	1,207	725
Income taxes	(72)	102	143	285
Equity in losses of unconsolidated affiliates	(9)	(7)	(18)	(10)
Net income	64	306	1,046	430
Net (loss) income attributable to noncontrolling interests and preference stock dividends	(16)	39	(30)	(10)
Net income attributable to common shareholders	$ 80	$ 267	$ 1,076	$ 440
Comprehensive income, net of income taxes				
Net income	$ 64	$ 306	$ 1,046	$ 430
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(14)	(12)	(28)	(23)
Actuarial loss reclassified to periodic benefit cost	49	46	98	93
Pension and non-pension postretirement benefit plan valuation adjustment	(2)	(1)	(58)	(3)

Unrealized (loss) gain on cash flow hedges	(1)		5	(7)
Unrealized (loss) gain on equity investments		(4)	3	(7)
Unrealized gain on foreign currency translation	2		3	6
Unrealized gain on marketable securities	1	2	2	
Other comprehensive income	35	31	25	59
Comprehensive income	99	337	1,071	489
Comprehensive (loss) income attributable to noncontrolling interests and preference stock dividends	(16)	39	(32)	(10)
Comprehensive income attributable to common shareholders	$ 115	$ 298	$ 1,103	$ 499
Average shares of common stock outstanding:				
Basic	934	924	931	923
Diluted	936	926	932	926
Earnings per average common share:				
Basic	$ 0.09	$ 0.29	$ 1.16	$ 0.48
Diluted	$ 0.09	$ 0.29	$ 1.15	$ 0.48
Dividends declared per common share	$ 0.33	$ 0.32	$ 0.66	$ 0.63

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income	$ 1,046	$ 430
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	2,591	2,396
Impairment of long-lived assets and losses on regulatory assets	445	239
Gain on sales of assets	(5)	(40)
Bargain purchase gain	(226)	
Deferred income taxes and amortization of investment tax credits	107	261
Net fair value changes related to derivatives	230	194
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(284)	(114)
Other non-cash operating activities	415	1,056
Changes in assets and liabilities:		
Accounts receivable	342	86
Inventories	(23)	89
Accounts payable and accrued expenses	(811)	(363)
Option premiums paid, net	(8)	(10)
Collateral (posted) received, net	(173)	710
Income taxes	58	470
Pension and non-pension postretirement benefit contributions	(325)	(258)
Other assets and liabilities	(481)	(593)
Net cash flows provided by operating activities	2,898	4,553
Cash flows from investing activities		
Capital expenditures	(3,845)	(4,489)
Proceeds from nuclear decommissioning trust fund sales	5,213	4,977
Investment in nuclear decommissioning trust funds	(5,339)	(5,094)
Acquisition of businesses, net	(212)	(6,642)
Proceeds from sales of long-lived assets	211	45
Proceeds from termination of direct financing lease investment		360
Change in restricted cash	1	15
Other investing activities	(9)	(49)
Net cash flows used in investing activities	(3,980)	(10,877)
Cash flows from financing activities		
Changes in short-term borrowings	422	(798)
Proceeds from short-term borrowings with maturities greater than 90 days	576	194
Repayments on short-term borrowings with maturities greater than 90 days	(510)	(315)
Issuance of long-term debt	981	3,174
Retirement of long-term debt	(1,049)	(217)
Dividends paid on common stock	(607)	(582)
Common stock issued from treasury stock	1,150	
Proceeds from employee stock plans	43	17
Other financing activities	(23)	(4)

Net cash flows provided by financing activities	983	1,469
Decrease in cash and cash equivalents	(99)	(4,855)
Cash and cash equivalents at beginning of period	635	6,502
Cash and cash equivalents at end of period	$ 536	$ 1,647

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 536	$ 635
Restricted cash and cash equivalents	252	253
Deposit with IRS	1,250	1,250
Accounts receivable, net		
Customer	3,825	4,158
Other	958	1,201
Mark-to-market derivative assets	833	917
Unamortized energy contract assets	84	88
Inventories, net		
Fossil fuel and emission allowances	334	364
Materials and supplies	1,267	1,274
Regulatory assets	1,293	1,342
Other	1,600	930
Total current assets	12,232	12,412
Property, plant and equipment, net	72,748	71,555
Deferred debits and other assets		
Regulatory assets	9,945	10,046
Nuclear decommissioning trust funds	12,641	11,061
Investments	638	629
Goodwill	6,677	6,677
Mark-to-market derivative assets	464	492
Unamortized energy contract assets	419	447
Pledged assets for Zion Station decommissioning	75	113
Other	1,265	1,472
Total deferred debits and other assets	32,124	30,937
Total assets[(a)]	$ 117,104	$ 114,904

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 1,757	$ 1,267
Long-term debt due within one year	3,619	2,430
Accounts payable	3,134	3,441
Accrued expenses	2,878	3,460
Payables to affiliates	8	8
Regulatory liabilities	574	602
Mark-to-market derivative liabilities	244	282
Unamortized energy contract liabilities	340	407
Renewable energy credit obligation	308	428
PHI merger related obligation	126	151
Other	977	981
Total current liabilities	13,965	13,457
Long-term debt	30,315	31,575
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	18,521	18,138
Asset retirement obligations	9,848	9,111
Pension obligations	4,082	4,248
Non-pension postretirement benefit obligations	1,955	1,848
Spent nuclear fuel obligation	1,139	1,024
Regulatory liabilities	4,398	4,187
Mark-to-market derivative liabilities	417	392
Unamortized energy contract liabilities	705	830
Payable for Zion Station decommissioning		14
Other	1,828	1,827
Total deferred credits and other liabilities	42,893	41,619
Total liabilities[(a)]	87,814	87,292
Commitments and contingencies		
Shareholders equity		
Common stock (No par value, 2000 shares authorized, 960 shares and 924 shares outstanding at June 30, 2017 and December 31, 2016, respectively)	18,860	18,794
Treasury stock, at cost (2 shares and 35 shares at June 30, 2017 and December 31, 2016, respectively)	(123)	(2,327)
Retained earnings	11,442	12,030
Accumulated other comprehensive loss, net	(2,633)	(2,660)
Total shareholders equity	27,546	25,837
Noncontrolling interests	1,744	1,775
Total equity	29,290	27,612

Total liabilities and shareholders equity	$ 117,104	$ 114,904

(a) Exelon s consolidated assets include $8,385 million and $8,893 million at June 30, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $3,021 million and $3,356 million at June 30, 2017 and December 31, 2016, 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, 2016	958,778	$ 18,794	$ (2,327)	$ 12,030	$ (2,660)	$ 1,775	$ 27,612
Net income (loss)				1,076		(30)	1,046
Long-term incentive plan activity	2,494	23					23
Employee stock purchase plan issuances	648	43					43
Common stock issued from treasury stock			2,204	(1,054)			1,150
Changes in equity of noncontrolling interests						1	1
Common stock dividends				(610)			(610)
Other comprehensive income (loss), net of income taxes					27	(2)	25
Balance, June 30, 2017	961,920	$ 18,860	$ (123)	$ 11,442	$ (2,633)	$ 1,744	$ 29,290

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Operating revenues	$ 3,906	$ 3,231	$ 8,463	$ 7,702
Operating revenues from affiliates	268	358	598	627
Total operating revenues	4,174	3,589	9,061	8,329
Operating expenses				
Purchased power and fuel	2,156	1,575	4,952	4,015
Purchased power and fuel from affiliates	1	2	3	5
Operating and maintenance	1,824	1,369	3,132	2,665
Operating and maintenance from affiliates	186	161	365	332
Depreciation and amortization	334	408	637	697
Taxes other than income	140	118	282	244
Total operating expenses	4,641	3,633	9,371	7,958
Gain on sales of assets		31	4	31
Bargain purchase gain			226	
Operating (loss) income	(467)	(13)	(80)	402
Other income and (deductions)				
Interest expense, net	(120)	(89)	(209)	(176)
Interest expense to affiliates	(9)	(10)	(19)	(20)
Other, net	181	117	440	210
Total other income and (deductions)	52	18	212	14
(Loss) income before income taxes	(415)	5	132	416
Income taxes	(158)	(31)	(31)	120
Equity in losses of unconsolidated affiliates	(9)	(8)	(19)	(11)
Net (loss) income	(266)	28	144	285
Net (loss) income attributable to noncontrolling interests	(16)	36	(30)	(17)
Net (loss) income attributable to membership interest	$ (250)	$ (8)	$ 174	$ 302
Comprehensive (loss) income, net of income taxes				
Net (loss) income	$ (266)	$ 28	$ 144	$ 285
Other comprehensive income (loss), net of income taxes				
Unrealized (loss) gain on cash flow hedges	(1)	1	5	(4)
Unrealized (loss) gain on equity investments		(2)	4	(4)
Unrealized gain on foreign currency translation	2		3	6
Unrealized gain on marketable securities		1		

Other comprehensive income (loss)	1		12	(2)
Comprehensive (loss) income	(265)	28	156	283
Comprehensive (loss) income attributable to noncontrolling interests	(16)	36	(32)	(17)
Comprehensive (loss) income attributable to membership interest	$ (249)	$ (8)	$ 188	$ 300

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities		
Net income	$ 144	$ 285
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	1,415	1,467
Impairment of long-lived assets	445	179
Gain on sales of assets	(4)	(31)
Bargain purchase gain	(226)	
Deferred income taxes and amortization of investment tax credits	(173)	(59)
Net fair value changes related to derivatives	235	199
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(284)	(114)
Other non-cash operating activities	121	169
Changes in assets and liabilities:		
Accounts receivable	192	123
Receivables from and payables to affiliates, net	8	(77)
Inventories	(5)	57
Accounts payable and accrued expenses	(328)	(228)
Option premiums paid, net	(8)	(10)
Collateral (posted) received, net	(163)	720
Income taxes	(99)	41
Pension and non-pension postretirement benefit contributions	(116)	(117)
Other assets and liabilities	(180)	(217)
Net cash flows provided by operating activities	974	2,387
Cash flows from investing activities		
Capital expenditures	(1,189)	(2,051)
Proceeds from nuclear decommissioning trust fund sales	5,213	4,977
Investment in nuclear decommissioning trust funds	(5,339)	(5,094)
Acquisition of businesses, net	(212)	(1)
Proceeds from sale of long-lived assets	210	30
Change in restricted cash	(8)	25
Other investing activities	(32)	(96)
Net cash flows used in investing activities	(1,357)	(2,210)
Cash flows from financing activities		
Changes in short-term borrowings	(51)	
Proceeds from short-term borrowings with maturities greater than 90 days	76	194
Repayments of short-term borrowings with maturities greater than 90 days	(10)	(15)
Issuance of long-term debt	779	173
Retirement of long-term debt	(295)	(131)
Changes in Exelon intercompany money pool	196	(429)
Distribution to member	(330)	(111)
Contribution from member		45
Other financing activities	(7)	39

Net cash flows provided by (used in) financing activities	358	(235)
Decrease in cash and cash equivalents	(25)	(58)
Cash and cash equivalents at beginning of period	290	431
Cash and cash equivalents at end of period	$ 265	$ 373

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 265	$ 290
Restricted cash and cash equivalents	166	158
Accounts receivable, net		
Customer	2,242	2,433
Other	447	558
Mark-to-market derivative assets	833	917
Receivables from affiliates	143	156
Unamortized energy contract assets	84	88
Inventories, net		
Fossil fuel and emission allowances	272	292
Materials and supplies	901	935
Other	1,241	701
Total current assets	6,594	6,528
Property, plant and equipment, net	25,261	25,585
Deferred debits and other assets		
Nuclear decommissioning trust funds	12,641	11,061
Investments	426	418
Goodwill	47	47
Mark-to-market derivative assets	453	476
Prepaid pension asset	1,590	1,595
Pledged assets for Zion Station decommissioning	75	113
Unamortized energy contract assets	418	447
Deferred income taxes	5	16
Other	620	688
Total deferred debits and other assets	16,275	14,861
Total assets[(a)]	$ 48,130	$ 46,974

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 716	$ 699
Long-term debt due within one year	1,828	1,117
Accounts payable	1,527	1,610
Accrued expenses	722	989
Payables to affiliates	132	137
Borrowings from Exelon intercompany money pool	251	55
Mark-to-market derivative liabilities	225	263
Unamortized energy contract liabilities	61	72
Renewable energy credit obligation	308	428
Other	294	313
Total current liabilities	6,064	5,683
Long-term debt	7,010	7,202
Long-term debt to affiliate	916	922
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,578	5,585
Asset retirement obligations	9,655	8,922
Non-pension postretirement benefit obligations	922	930
Spent nuclear fuel obligation	1,139	1,024
Payables to affiliates	2,871	2,608
Mark-to-market derivative liabilities	180	153
Unamortized energy contract liabilities	67	80
Payable for Zion Station decommissioning		14
Other	598	595
Total deferred credits and other liabilities	21,010	19,911
Total liabilities[(a)]	35,000	33,718
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	9,308	9,261
Undistributed earnings	2,119	2,275
Accumulated other comprehensive loss, net	(40)	(54)
Total member s equity	11,387	11,482
Noncontrolling interests	1,743	1,774
Total equity	13,130	13,256
Total liabilities and equity	$ 48,130	$ 46,974

(a) Generation s consolidated assets include $8,342 million and $8,817 million at June 30, 2017 and December 31, 2016, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include $2,900 million and $3,170 million at June 30, 2017 and December 31, 2016, 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)

	Member s Equity				
(In millions)	**Membership Interest**	**Undistributed Earnings**	**Accumulated Other Comprehensive Loss, net**	**Noncontrolling Interests**	**Total Equity**
Balance, December 31, 2016	$ 9,261	$ 2,275	$ (54)	$ 1,774	$ 13,256
Net income (loss)		174		(30)	144
Changes in equity of noncontrolling interests				1	1
Distribution of net retirement benefit obligation to member	49				49
Allocation of tax benefit from member	(2)				(2)
Distribution to member		(330)			(330)
Other comprehensive income (loss), net of income taxes			14	(2)	12
Balance, June 30, 2017	$ 9,308	$ 2,119	$ (40)	$ 1,743	$ 13,130

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2017**	**2016**	**2017**	**2016**
Operating revenues				
Electric operating revenues	$ 1,354	$ 1,283	$ 2,647	$ 2,527
Operating revenues from affiliates	3	3	9	8
Total operating revenues	1,357	1,286	2,656	2,535
Operating expenses				
Purchased power	360	326	689	668
Purchased power from affiliate	18	13	24	18
Operating and maintenance	312	318	620	623
Operating and maintenance from affiliate	65	50	127	113
Depreciation and amortization	211	190	419	379
Taxes other than income	72	65	144	141
Total operating expenses	1,038	962	2,023	1,942
Gain on sales of assets				5
Operating income	319	324	633	598
Other income and (deductions)				
Interest expense, net	(98)	(88)	(179)	(170)
Interest expense to affiliates	(3)	(3)	(6)	(7)
Other, net	4	3	8	7
Total other income and (deductions)	(97)	(88)	(177)	(170)
Income before income taxes	222	236	456	428
Income taxes	104	91	197	168
Net income	$ 118	$ 145	$ 259	$ 260
Comprehensive income	$ 118	$ 145	$ 259	$ 260

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities		
Net income	$ 259	$ 260
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	419	379
Deferred income taxes and amortization of investment tax credits	235	222
Other non-cash operating activities	58	83
Changes in assets and liabilities:		
Accounts receivable	12	(36)
Receivables from and payables to affiliates, net	(4)	1
Inventories	(2)	7
Accounts payable and accrued expenses	(182)	(42)
Collateral (posted) received, net	(8)	(10)
Income taxes	4	261
Pension and non-pension postretirement benefit contributions	(37)	(35)
Other assets and liabilities	34	38
Net cash flows provided by operating activities	788	1,128
Cash flows from investing activities		
Capital expenditures	(1,168)	(1,334)
Change in restricted cash	(10)	
Other investing activities	12	21
Net cash flows used in investing activities	(1,166)	(1,313)
Cash flows from financing activities		
Changes in short-term borrowings	389	(259)
Issuance of long-term debt		1,200
Contributions from parent	184	113
Dividends paid on common stock	(211)	(183)
Other financing activities	(1)	(17)
Net cash flows provided by financing activities	361	854
(Decrease) increase in cash and cash equivalents	(17)	669
Cash and cash equivalents at beginning of period	56	67
Cash and cash equivalents at end of period	$ 39	$ 736

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 39	$ 56
Restricted cash	12	2
Accounts receivable, net		
Customer	529	528
Other	211	218
Receivables from affiliates	386	356
Inventories, net	160	159
Regulatory assets	182	190
Other	57	45
Total current assets	1,576	1,554
Property, plant and equipment, net	20,019	19,335
Deferred debits and other assets		
Regulatory assets	1,050	977
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,364	2,170
Prepaid pension asset	1,283	1,343
Other	237	325
Total deferred debits and other assets	7,565	7,446
Total assets	$ 29,160	$ 28,335

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 389	$
Long-term debt due within one year	1,125	425
Accounts payable	547	645
Accrued expenses	1,107	1,250
Payables to affiliates	67	65
Customer deposits	115	121
Regulatory liabilities	269	329
Mark-to-market derivative liability	19	19
Other	112	84
Total current liabilities	3,750	2,938
Long-term debt	5,911	6,608
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,600	5,364
Asset retirement obligations	122	119
Non-pension postretirement benefits obligations	229	239
Regulatory liabilities	3,585	3,369
Mark-to-market derivative liability	237	239
Other	541	529
Total deferred credits and other liabilities	10,314	9,859
Total liabilities	20,180	19,610
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	6,357	6,150
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,674	2,626
Total shareholders equity	8,980	8,725
Total liabilities and shareholders equity	$ 29,160	$ 28,335

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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, 2016	$ 1,588	$ 6,150	$ (1,639)	$ 2,626	$ 8,725
Net income			259		259
Appropriation of retained earnings for future dividends			(259)	259	
Common stock dividends				(211)	(211)
Contribution from parent		184			184
Parent tax matter indemnification		23			23
Balance, June 30, 2017	$ 1,588	$ 6,357	$ (1,639)	$ 2,674	$ 8,980

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$ 548	$ 585	$ 1,138	$ 1,228
Natural gas operating revenues	80	77	285	273
Operating revenues from affiliates	2	2	3	4
Total operating revenues	630	664	1,426	1,505
Operating expenses				
Purchased power	136	130	292	295
Purchased fuel	27	23	113	100
Purchased power from affiliate	34	64	79	142
Operating and maintenance	153	157	326	333
Operating and maintenance from affiliates	37	33	72	72
Depreciation and amortization	71	67	141	134
Taxes other than income	35	38	74	80
Total operating expenses	493	512	1,097	1,156
Operating income	137	152	329	349
Other income and (deductions)				
Interest expense, net	(28)	(28)	(56)	(56)
Interest expense to affiliates	(3)	(3)	(6)	(6)
Other, net	2	2	3	4
Total other income and (deductions)	(29)	(29)	(59)	(58)
Income before income taxes	108	123	270	291
Income taxes	20	23	55	67
Net income	$ 88	$ 100	$ 215	$ 224
Comprehensive income	$ 88	$ 100	$ 215	$ 224

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income	$ 215	$ 224
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	141	134
Deferred income taxes and amortization of investment tax credits	39	51
Other non-cash operating activities	22	27
Changes in assets and liabilities:		
Accounts receivable	26	(1)
Receivables from and payables to affiliates, net	(10)	(2)
Inventories	7	19
Accounts payable and accrued expenses	(30)	(19)
Income taxes	51	31
Pension and non-pension postretirement benefit contributions	(23)	(29)
Other assets and liabilities	(70)	(96)
Net cash flows provided by operating activities	368	339
Cash flows from investing activities		
Capital expenditures	(367)	(299)
Changes in Exelon intercompany money pool	121	
Other investing activities	4	8
Net cash flows used in investing activities	(242)	(291)
Cash flows from financing activities		
Dividends paid on common stock	(144)	(139)
Other financing activities		(1)
Net cash flows used in financing activities	(144)	(140)
Decrease in cash and cash equivalents	(18)	(92)
Cash and cash equivalents at beginning of period	63	295
Cash and cash equivalents at end of period	$ 45	$ 203

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 45	$ 63
Restricted cash and cash equivalents	4	4
Accounts receivable, net		
Customer	258	306
Other	135	131
Receivables from affiliates	1	4
Receivable from Exelon intercompany pool	10	131
Inventories, net		
Fossil fuel	25	35
Materials and supplies	30	27
Prepaid utility taxes	77	9
Regulatory assets	46	29
Other	25	18
Total current assets	656	757
Property, plant and equipment, net	7,758	7,565
Deferred debits and other assets		
Regulatory assets	1,732	1,681
Investments	24	25
Receivable from affiliates	506	438
Prepaid pension asset	354	345
Other	11	20
Total deferred debits and other assets	2,627	2,509
Total assets	$ 11,041	$ 10,831

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 500	$
Accounts payable	278	342
Accrued expenses	136	104
Payables to affiliates	50	63
Customer deposits	63	61
Regulatory liabilities	155	127
Other	31	30
Total current liabilities	1,213	727
Long-term debt	2,080	2,580
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,128	3,006
Asset retirement obligations	28	28
Non-pension postretirement benefits obligations	289	289
Regulatory liabilities	544	517
Other	89	85
Total deferred credits and other liabilities	4,078	3,925
Total liabilities	7,555	7,416
Commitments and contingencies		
Shareholder s equity		
Common stock	2,473	2,473
Retained earnings	1,012	941
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,486	3,415
Total liabilities and shareholder s equity	$ 11,041	$ 10,831

See the Combined Notes to Consolidated Financial Statements

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, 2016	$ 2,473	$ 941	$ 1	$ 3,415
Net income		215		215
Common stock dividends		(144)		(144)
Balance, June 30, 2017	$ 2,473	$ 1,012	$ 1	$ 3,486

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2017**	**2016**	**2017**	**2016**
Operating revenues				
Electric operating revenues	$ 569	$ 582	$ 1,234	$ 1,260
Natural gas operating revenues	102	94	383	340
Operating revenues from affiliates	3	4	8	9
Total operating revenues	674	680	1,625	1,609
Operating expenses				
Purchased power	115	108	248	235
Purchased fuel	22	20	105	95
Purchased power from affiliate	97	133	231	304
Operating and maintenance	135	177	284	345
Operating and maintenance from affiliates	39	31	73	65
Depreciation and amortization	112	97	239	206
Taxes other than income	56	55	119	114
Total operating expenses	576	621	1,299	1,364
Operating income	98	59	326	245
Other income and (deductions)				
Interest expense, net	(22)	(20)	(46)	(40)
Interest expense to affiliates	(4)	(4)	(8)	(8)
Other, net	4	5	8	11
Total other income and (deductions)	(22)	(19)	(46)	(37)
Income before income taxes	76	40	280	208
Income taxes	31	6	111	73
Net income	45	34	169	135
Preference stock dividends		3		6
Net income attributable to common shareholder	$ 45	$ 31	$ 169	$ 129
Comprehensive income	$ 45	$ 34	$ 169	$ 135
Comprehensive income attributable to preference stock dividends		3		6
Comprehensive income attributable to common shareholder	$ 45	$ 31	$ 169	$ 129

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(In millions)	**2017**	**2016**
Cash flows from operating activities		
Net income	$ 169	$ 135
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	239	206
Impairment of long-lived assets and losses on regulatory assets		52
Deferred income taxes and amortization of investment tax credits	99	17
Other non-cash operating activities	35	60
Changes in assets and liabilities:		
Accounts receivable	77	11
Receivables from and payables to affiliates, net	(7)	6
Inventories	(5)	6
Accounts payable and accrued expenses	(83)	(5)
Income taxes	26	46
Pension and non-pension postretirement benefit contributions	(47)	(42)
Other assets and liabilities	(31)	(3)
Net cash flows provided by operating activities	472	489
Cash flows from investing activities		
Capital expenditures	(405)	(392)
Change in restricted cash	18	5
Other investing activities	4	12
Net cash flows used in investing activities	(383)	(375)
Cash flows from financing activities		
Changes in short-term borrowings	40	(2)
Retirement of long-term debt	(41)	(39)
Dividends paid on preference stock		(6)
Dividends paid on common stock	(99)	(90)
Contributions from parent		21
Other financing activities		(2)
Net cash flows used in financing activities	(100)	(118)
Decrease in cash and cash equivalents	(11)	(4)
Cash and cash equivalents at beginning of period	23	9
Cash and cash equivalents at end of period	$ 12	$ 5

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 12	$ 23
Restricted cash and cash equivalents	6	24
Accounts receivable, net		
Customer	312	395
Other	75	102
Receivables from affiliates	1	
Inventories, net		
Gas held in storage	31	30
Materials and supplies	42	38
Prepaid utility taxes		15
Regulatory assets	197	208
Other	4	7
Total current assets	680	842
Property, plant and equipment, net	7,283	7,040
Deferred debits and other assets		
Regulatory assets	495	504
Investments	13	12
Prepaid pension asset	310	297
Other	5	9
Total deferred debits and other assets	823	822
Total assets[(a)]	$ 8,786	$ 8,704

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 85	$ 45
Long-term debt due within one year		41
Accounts payable	205	205
Accrued expenses	100	175
Payables to affiliates	49	55
Customer deposits	113	110
Regulatory liabilities	67	50
Other	21	26
Total current liabilities	640	707
Long-term debt	2,282	2,281
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,322	2,219
Asset retirement obligations	22	21
Non-pension postretirement benefits obligations	201	205
Regulatory liabilities	90	110
Other	59	61
Total deferred credits and other liabilities	2,694	2,616
Total liabilities[(a)]	5,868	5,856
Commitments and contingencies		
Shareholders equity		
Common stock	1,421	1,421
Retained earnings	1,497	1,427
Total shareholders equity	2,918	2,848
Total liabilities and shareholders equity	$ 8,786	$ 8,704

(a) BGE s consolidated assets include $26 million at December 31, 2016 of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include $42 million at December 31, 2016 of BGE s consolidated VIE for which the VIE creditors do not have recourse to BGE. BGE has no interests in any VIEs as of June 30, 2017. See Note 3 Variable Interest Entities.

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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, 2016	$ 1,421	$ 1,427	$ 2,848
Net income		169	169
Common stock dividends		(99)	(99)
Balance, June 30, 2017	$ 1,421	$ 1,497	$ 2,918

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Successor				Predecessor
(In millions)	**Three Months Ended June 30, 2017**	**Three Months Ended June 30, 2016**	**Six Months Ended June 30, 2017**	**March 24 to June 30, 2016**	**January 1 to March 23, 2016**
Operating revenues					
Electric operating revenues	$ 1,040	$ 1,030	$ 2,138	$ 1,120	$ 1,096
Natural gas operating revenues	22	26	87	28	57
Operating revenues from affiliates	12	10	23	23	
Total operating revenues	1,074	1,066	2,248	1,171	1,153
Operating expenses					
Purchased power	259	263	547	288	471
Purchased fuel	9	9	39	11	26
Purchased power and fuel from affiliates	115	144	259	155	
Operating and maintenance	231	223	454	670	294
Operating and maintenance from affiliates	38	23	70	25	
Depreciation and amortization	165	160	332	174	152
Taxes other than income	110	108	221	123	105
Total operating expenses	927	930	1,922	1,446	1,048
Gain on sales of assets	1		1		
Operating income (loss)	148	136	327	(275)	105
Other income and (deductions)					
Interest expense, net	(59)	(66)	(122)	(71)	(65)
Other, net	13	11	26	12	(4)
Total other income and (deductions)	(46)	(55)	(96)	(59)	(69)
Income (loss) before income taxes	102	81	231	(334)	36
Income taxes	36	29	26	(77)	17
Net income (loss)	$ 66	$ 52	$ 205	$ (257)	$ 19
Comprehensive income (loss), net of income taxes					
Net income (loss)	$ 66	$ 52	$ 205	$ (257)	$ 19
Other comprehensive income, net of income taxes					
Pension and non-pension postretirement benefit plans:					
Actuarial loss reclassified to periodic cost					1
Other comprehensive income					1
Comprehensive income (loss)	$ 66	$ 52	$ 205	$ (257)	$ 20

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	*Successor* Six Months Ended June 30, 2017	March 24 to June 30, 2016	*Predecessor* January 1 to March 23, 2016
Cash flows from operating activities			
Net income (loss)	$ 205	$ (257)	$ 19
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization	332	174	152
Gain on sale of long-lived assets	(1)		
Deferred income taxes and amortization of investment tax credits	59	(16)	19
Net fair value changes related to derivatives			18
Other non-cash operating activities	28	444	46
Changes in assets and liabilities:			
Accounts receivable	(3)	56	(28)
Receivables from and payables to affiliates, net	(7)	39	
Inventories	(19)		(4)
Accounts payable and accrued expenses	(61)	(35)	42
Income taxes	87	22	12
Pension and non-pension postretirement benefit contributions	(68)	(2)	(4)
Other assets and liabilities	(149)	(237)	(8)
Net cash flows provided by operating activities	403	188	264
Cash flows from investing activities			
Capital expenditures	(671)	(339)	(273)
Proceeds from sales of long-lived assets	1	15	
Changes in restricted cash	3	(34)	3
Purchases of investments			(68)
Other investing activities		8	(5)
Net cash flows used in investing activities	(667)	(350)	(343)
Cash flows from financing activities			
Changes in short-term borrowings	45	(537)	(121)
Proceeds from short-term borrowings with maturities greater than 90 days			500
Repayments of short-term borrowings with maturities greater than 90 days	(500)	(300)	
Issuance of long-term debt	202	1	
Retirement of long-term debt	(120)	(16)	(11)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation			2
Distribution to member	(131)	(124)	
Contribution from member	751	1,088	
Change in Exelon intercompany money pool		28	
Other financing activities	(2)	(3)	2
Net cash flows provided by financing activities	245	137	372

(Decrease) increase in cash and cash equivalents	(19)	(25)	293
Cash and cash equivalents at beginning of period	170	319	26
Cash and cash equivalents at end of period	$ 151	$ 294	$ 319

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Successor	
(In millions)	**June 30, 2017**	**December 31, 2016**
ASSETS		
Current assets		
Cash and cash equivalents	$ 151	$ 170
Restricted cash and cash equivalents	40	43
Accounts receivable, net		
Customer	484	496
Other	199	283
Receivable from affiliates	1	
Inventories, net		
Gas held in storage	6	6
Materials and supplies	134	116
Regulatory assets	605	653
Other	86	71
Total current assets	1,706	1,838
Property, plant and equipment, net	12,014	11,598
Deferred debits and other assets		
Regulatory assets	2,715	2,851
Investments	132	133
Goodwill	4,005	4,005
Long-term note receivable	4	4
Prepaid pension asset	529	509
Deferred income taxes	6	6
Other	79	81
Total deferred debits and other assets	7,470	7,589
Total assets[(a)]	$ 21,190	$ 21,025

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

	Successor	
(In millions)	**June 30, 2017**	**December 31, 2016**
LIABILITIES AND MEMBER S EQUITY		
Current liabilities		
Short-term borrowings	$ 67	$ 522
Long-term debt due within one year	160	253
Accounts payable	415	458
Accrued expenses	259	272
Payables to affiliates	86	94
Unamortized energy contract liabilities	279	335
Customer deposits	119	123
Merger related obligation	73	101
Regulatory liabilities	68	79
Other	36	47
Total current liabilities	1,562	2,284
Long-term debt	5,792	5,645
Deferred credits and other liabilities		
Regulatory liabilities	151	158
Deferred income taxes and unamortized investment tax credits	3,844	3,775
Asset retirement obligations	14	14
Non-pension postretirement benefit obligations	135	134
Unamortized energy contract liabilities	638	750
Other	213	249
Total deferred credits and other liabilities	4,995	5,080
Total liabilities[(a)]	12,349	13,009
Commitments and contingencies		
Member s equity		
Membership interest	8,828	8,077
Undistributed earnings (losses)	13	(61)
Total member s equity	8,841	8,016
Total liabilities and member s equity	$ 21,190	$ 21,025

(a) PHI s consolidated total assets include $43 million and $49 million at June 30, 2017 and December 31, 2016, respectively, of PHI s consolidated VIE that can only be used to settle the liabilities of the VIE. PHI s consolidated total liabilities include $121 million and $143 million at June 30, 2017 and December 31, 2016, 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
Successor			
Balance, December 31, 2016	$ 8,077	$ (61)	$ 8,016
Net income		205	205
Distribution to member		(131)	(131)
Contribution from member	751		751
Balance, June 30, 2017	$ 8,828	$ 13	$ 8,841

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POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$ 513	$ 508	$ 1,042	$ 1,058
Operating revenues from affiliates	1	1	3	3
Total operating revenues	514	509	1,045	1,061
Operating expenses				
Purchased power	74	64	157	256
Purchased power from affiliates	69	88	152	95
Operating and maintenance	106	100	208	389
Operating and maintenance from affiliates	14	9	26	10
Depreciation and amortization	78	70	160	144
Taxes other than income	90	89	180	182
Total operating expenses	431	420	883	1,076
Gain on sales of assets	1	8	1	8
Operating income (loss)	84	97	163	(7)
Other income and (deductions)				
Interest expense, net	(28)	(31)	(58)	(68)
Other, net	7	6	15	14
Total other income and (deductions)	(21)	(25)	(43)	(54)
Income (loss) before income taxes	63	72	120	(61)
Income taxes	20	23	19	(1)
Net income (loss)	$ 43	$ 49	$ 101	$ (60)
Comprehensive income (loss)	$ 43	$ 49	$ 101	$ (60)

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POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income (loss)	$ 101	$ (60)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	160	144
Deferred income taxes and amortization of investment tax credits	35	20
Gain on sale of long-lived assets	(1)	
Other non-cash operating activities		158
Changes in assets and liabilities:		
Accounts receivable	(33)	(41)
Receivables from and payables to affiliates, net	(4)	47
Inventories	(10)	1
Accounts payable and accrued expenses	(45)	(19)
Income taxes	46	165
Pension and non-pension postretirement benefit contributions	(65)	(3)
Other assets and liabilities	(55)	(47)
Net cash flows provided by operating activities	129	365
Cash flows from investing activities		
Capital expenditures	(291)	(256)
Proceeds from sale of long-lived asset	1	12
Purchases of investments		(31)
Changes in restricted cash	(1)	(31)
Other investing activities	(2)	(1)
Net cash flows used in investing activities	(293)	(307)
Cash flows from financing activities		
Changes in short-term borrowings	(23)	(64)
Issuance of long-term debt	202	1
Retirement of long-term debt	(7)	(5)
Dividends paid on common stock	(58)	(55)
Contribution from parent	161	187
Other financing activities	(1)	
Net cash flows provided by financing activities	274	64
Increase in cash and cash equivalents	110	122
Cash and cash equivalents at beginning of period	9	5
Cash and cash equivalents at end of period	$ 119	$ 127

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POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 119	$ 9
Restricted cash and cash equivalents	34	33
Accounts receivable, net		
Customer	256	235
Other	114	150
Inventories, net	73	63
Regulatory assets	165	162
Other	7	32
Total current assets	768	684
Property, plant and equipment, net	5,759	5,571
Deferred debits and other assets		
Regulatory assets	682	690
Investments	102	102
Prepaid pension asset	332	282
Other	5	6
Total deferred debits and other assets	1,121	1,080
Total assets	$ 7,648	$ 7,335

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POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$	$ 23
Long-term debt due within one year	18	16
Accounts payable	157	209
Accrued expenses	117	113
Payables to affiliates	70	74
Customer deposits	53	53
Regulatory liabilities	5	11
Merger related obligation	49	68
Other	16	29
Total current liabilities	485	596
Long-term debt	2,527	2,333
Deferred credits and other liabilities		
Regulatory liabilities	17	20
Deferred income taxes and unamortized investment tax credits	1,950	1,910
Non-pension postretirement benefit obligations	40	43
Other	125	133
Total deferred credits and other liabilities	2,132	2,106
Total liabilities	5,144	5,035
Commitments and contingencies		
Shareholder s equity		
Common stock	1,470	1,309
Retained earnings	1,034	991
Total shareholder s equity	2,504	2,300
Total liabilities and shareholder s equity	$ 7,648	$ 7,335

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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, 2016	$ 1,309	$ 991	$ 2,300
Net income		101	101
Common stock dividends		(58)	(58)
Contribution from parent	161		161
Balance, June 30, 2017	$ 1,470	$ 1,034	$ 2,504

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DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$ 258	$ 253	$ 553	$ 554
Natural gas operating revenues	22	26	87	85
Operating revenues from affiliates	2	2	4	4
Total operating revenues	282	281	644	643
Operating expenses				
Purchased power	64	70	141	216
Purchased fuel	9	9	38	35
Purchased power from affiliate	40	43	91	47
Operating and maintenance	66	73	133	277
Operating and maintenance from affiliates	8	5	15	6
Depreciation and amortization	40	38	79	76
Taxes other than income	14	13	28	28
Total operating expenses	241	251	525	685
Operating income (loss)	41	30	119	(42)
Other income and (deductions)				
Interest expense, net	(13)	(13)	(25)	(25)
Other, net	3	3	6	6
Total other income and (deductions)	(10)	(10)	(19)	(19)
Income (loss) before income taxes	31	20	100	(61)
Income taxes	12	8	24	(1)
Net income (loss)	$ 19	$ 12	$ 76	$ (60)
Comprehensive income (loss)	$ 19	$ 12	$ 76	$ (60)

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DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	2016
Cash flows from operating activities		
Net income (loss)	$ 76	$ (60)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	79	76
Deferred income taxes and amortization of investment tax credits	33	23
Other non-cash operating activities	(3)	121
Changes in assets and liabilities:		
Accounts receivable	12	30
Receivables from and payables to affiliates, net	(2)	15
Inventories	(3)	1
Accounts payable and accrued expenses	18	(2)
Collateral received		1
Income taxes	13	66
Other assets and liabilities	(29)	(51)
Net cash flows provided by operating activities	194	220
Cash flows from investing activities		
Capital expenditures	(192)	(182)
Changes in restricted cash		(1)
Other investing activities	1	3
Net cash flows used in investing activities	(191)	(180)
Cash flows from financing activities		
Changes in short-term borrowings	25	(105)
Retirement of long-term debt	(14)	
Dividends paid on common stock	(54)	(38)
Contribution from parent		113
Net cash flows used in financing activities	(43)	(30)
(Decrease) Increase in cash and cash equivalents	(40)	10
Cash and cash equivalents at beginning of period	46	5
Cash and cash equivalents at end of period	$ 6	$ 15

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DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 6	$ 46
Accounts receivable, net		
Customer	124	136
Other	49	63
Receivables from affiliates		3
Inventories, net		
Gas held in storage	6	7
Materials and supplies	36	32
Regulatory assets	71	59
Other	19	24
Total current assets	311	370
Property, plant and equipment, net	3,412	3,273
Deferred debits and other assets		
Regulatory assets	299	289
Goodwill	8	8
Prepaid pension asset	200	206
Other	5	7
Total deferred debits and other assets	512	510
Total assets	$ 4,235	$ 4,153

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DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$ 25	$
Long-term debt due within one year	109	119
Accounts payable	125	88
Accrued expenses	35	36
Payables to affiliates	33	38
Customer deposits	35	36
Regulatory liabilities	43	43
Merger related obligation	3	13
Other	9	8
Total current liabilities	417	381
Long-term debt	1,217	1,221
Deferred credits and other liabilities		
Regulatory liabilities	95	97
Deferred income taxes and unamortized investment tax credits	1,092	1,056
Non-pension postretirement benefit obligations	20	19
Other	46	53
Total deferred credits and other liabilities	1,253	1,225
Total liabilities	2,887	2,827
Commitments and contingencies		
Shareholder s equity		
Common stock	764	764
Retained earnings	584	562
Total shareholder s equity	1,348	1,326
Total liabilities and shareholder s equity	$ 4,235	$ 4,153

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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, 2016	$ 764	$ 562	$ 1,326
Net income		76	76
Common stock dividends		(54)	(54)
Balance, June 30, 2017	$ 764	$ 584	$ 1,348

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Operating revenues				
Electric operating revenues	$ 269	$ 269	$ 543	$ 559
Operating revenues from affiliates	1	1	1	2
Total operating revenues	270	270	544	561
Operating expenses				
Purchased power	121	129	250	285
Purchased power from affiliates	7	12	16	13
Operating and maintenance	71	63	139	275
Operating and maintenance from affiliates	7	5	13	5
Depreciation and amortization	37	41	72	81
Taxes other than income	2	2	4	4
Total operating expenses	245	252	494	663
Gain on sale of assets		1		1
Operating income (loss)	25	19	50	(101)
Other income and (deductions)				
Interest expense, net	(15)	(16)	(30)	(32)
Other, net	2	2	4	5
Total other income and (deductions)	(13)	(14)	(26)	(27)
Income (loss) before income taxes	12	5	24	(128)
Income taxes	4	2	(12)	(31)
Net income (loss)	$ 8	$ 3	$ 36	$ (97)
Comprehensive income (loss)	$ 8	$ 3	$ 36	$ (97)

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Cash flows from operating activities		
Net income (loss)	$ 36	$ (97)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation and amortization	72	81
Deferred income taxes and amortization of investment tax credits	(8)	(28)
Other non-cash operating activities	7	138
Changes in assets and liabilities:		
Accounts receivable	18	31
Receivables from and payables to affiliates, net	(6)	8
Inventories	(3)	(2)
Accounts payable and accrued expenses	3	6
Income taxes	11	181
Other assets and liabilities	(53)	(110)
Net cash flows provided by operating activities	77	208
Cash flows from investing activities		
Capital expenditures	(175)	(164)
Proceeds from sale of long-lived asset		2
Changes in restricted cash	2	1
Other investing activities		1
Net cash flows used in investing activities	(173)	(160)
Cash flows from financing activities		
Changes in short-term borrowings	42	(5)
Retirement of long-term debt	(17)	(22)
Dividends paid on common stock	(22)	(11)
Contribution from parent		139
Other financing activities	(1)	(1)
Net cash flows provided by financing activities	2	100
(Decrease) Increase in cash and cash equivalents	(94)	148
Cash and cash equivalents at beginning of period	101	3
Cash and cash equivalents at end of period	$ 7	$ 151

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
ASSETS		
Current assets		
Cash and cash equivalents	$ 7	$ 101
Restricted cash and cash equivalents	7	9
Accounts receivable, net		
Customer	103	125
Other	46	44
Inventories, net	25	22
Prepaid utility taxes	37	
Regulatory assets	89	96
Other	4	2
Total current assets	318	399
Property, plant and equipment, net	2,628	2,521
Deferred debits and other assets		
Regulatory assets	406	405
Long-term note receivable	4	4
Prepaid pension asset	79	84
Other	43	44
Total deferred debits and other assets	532	537
Total assets[(a)]	$ 3,478	$ 3,457

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2017	December 31, 2016
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$ 42	$
Long-term debt due within one year	33	35
Accounts payable	122	132
Accrued expenses	56	38
Payables to affiliates	23	29
Customer deposits	31	33
Regulatory liabilities	20	25
Merger related obligation	21	20
Other	8	8
Total current liabilities	356	320
Long-term debt	1,105	1,120
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	911	917
Non-pension postretirement benefit obligations	35	34
Other	23	32
Total deferred credits and other liabilities	969	983
Total liabilities[(a)]	2,430	2,423
Commitments and contingencies		
Shareholder s equity		
Common stock	912	912
Retained earnings	136	122
Total shareholder s equity	1,048	1,034
Total liabilities and shareholder s equity	$ 3,478	$ 3,457

(a) ACE s consolidated total assets include $30 million and $32 million at June 30, 2017 and December 31, 2016, respectively, of ACE s consolidated VIE that can only be used to settle the liabilities of the VIE. ACE s consolidated total liabilities include $108 million and $126 million at June 30, 2017 and December 31, 2016, respectively, of ACE s consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 Variable Interest Entities.

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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, 2016	$ 912	$ 122	$ 1,034
Net income		36	36
Common stock dividends		(22)	(22)
Balance, June 30, 2017	$ 912	$ 136	$ 1,048

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	20
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	.	.	.		.			.	.	.	.		.	.			.	.	.	

1. Basis of Presentation (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. Prior to March 23, 2016, Exelon s principal, wholly owned subsidiaries included Generation, ComEd, PECO and BGE. On March 23, 2016, in conjunction with the Amended and Restated Agreement and Plan of Merger (the PHI Merger Agreement), Purple Acquisition Corp, a wholly owned subsidiary of Exelon, merged with and into PHI, with PHI continuing as the surviving entity as a wholly owned subsidiary of Exelon. PHI is a utility services holding company engaged through its principal wholly owned subsidiaries, Pepco, DPL and ACE, in the energy distribution and transmission businesses. Refer to Note 4 Mergers, Acquisitions and Dispositions for further information regarding the merger transaction.

The energy generation business includes:

Generation: 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. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

ComEd: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in northern Illinois, including the City of Chicago.

PECO: Purchase and regulated retail sale of electricity and the provision of electric 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 of natural gas distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

BGE: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in central Maryland, including the City of Baltimore.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Pepco: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in the District of Columbia and major portions of Prince George s County and Montgomery County in Maryland.

DPL: Purchase and regulated retail sale of electricity and the provision of electric 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: Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southern New Jersey.

Basis of Presentation (All Registrants)

As a result of the acquisition of PHI, Exelon s financial reporting reflects PHI s consolidated financial results subsequent to the March 23, 2016, acquisition date. Exelon has accounted for the merger transaction applying the acquisition method of accounting, which requires that identifiable assets acquired and liabilities assumed by Exelon to be reported in Exelon s financial statements at fair value, with any excess of the purchase price over the fair value of net assets acquired reported as goodwill. Exelon has pushed-down the application of the acquisition method of accounting to the consolidated financial statements of PHI such that the assets and liabilities of PHI are similarly recorded at their respective fair values, and goodwill has been established as of the acquisition date. Accordingly, the consolidated financial statements of PHI for periods before and after the March 23, 2016, acquisition date reflect different bases of accounting, and the financial positions and the results of operations of the predecessor and successor periods are not comparable. The acquisition method of accounting has not been pushed down to PHI s wholly owned subsidiary utility registrants, Pepco, DPL and ACE.

For financial statement purposes, beginning on March 24, 2016, disclosures related to Exelon now also apply to PHI, Pepco, DPL and ACE, unless otherwise noted.

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

During preparation of the June 30, 2017 financial statements, 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 Account 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 were corrected for the six months ended June 30, 2017, and will be revised within the first quarter 2018 Form 10-Q when the Consolidated Statements of Cash Flows for the three months ended March 31, 2017 will next be disclosed. 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 $2,284 million, $892 million, $620 million, $69 million and $221 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 has concluded that the errors are not material to the previously issued financial statements.

The accompanying consolidated financial statements as of June 30, 2017 and 2016 and for the three and six 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, 2016 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, 2017. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

2. New Accounting Standards (All Registrants)

New Accounting Standards Issued and Not Yet Adopted: 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. 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 such standards will not significantly impact the Registrants financial reporting.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions): Changes the criteria for recognizing revenue from a contract with a customer. The new revenue recognition guidance, including subsequent amendments, is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. Exelon has not early adopted this standard.

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. In addition, the Registrants will be required to capitalize costs to acquire new contracts, and amortize such costs in a manner consistent with the transfer to the customer of the associated goods or services. The Registrants currently expense those costs as incurred. These expenses are not expected to be material to the Registrants financial statements. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method).

The Registrants continue to assess the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. In conducting this assessment, the Registrants have performed the following key activities:

- Actively participate in the AICPA Power and Utilities Industry Task Force (Industry Task Force) process to identify implementation issues and support the development of related implementation guidance;

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

- Evaluate existing contracts and revenue streams for potential changes in the amounts and timing of recognizing revenues under the new guidance;
- Evaluate and select the transition method; and
- Develop and implement the approach and process for complying with the new revenue recognition disclosure requirements.

While there continues to be some ongoing activities in all of these areas, the Registrants have substantially completed the evaluation of their collective contracts and revenue streams, as well as the evaluation of the transition method. Based on the work completed thus far, the Registrants have reached the following preliminary conclusions:

- The Registrants expect to apply the new guidance using the full retrospective method;
- During the second quarter 2017, certain previously open implementation issues have been substantially resolved, including the collectability of utility tariff sale contracts and the accounting for bundled sales contracts. The Utility Registrants tariff sale contracts, including those with lower credit quality customers, are generally deemed to be probable of collection under the guidance and, thus, the timing of revenue recognition will continue to be based on the electricity or natural gas supplied in the period, consistent with current practice. Revenues recognized from bundled sales contracts are generally expected to be recognized based on the invoice price, consistent with current practice; and
- Contributions in aid of construction are expected to be outside of the scope of the standard and, therefore, will continue to be accounted for as a reduction to Property, Plant, and Equipment.

The Registrants generally anticipate that the implementation of the new standard will not have a material impact on the amount and timing of revenue recognition. However, certain implementation issues continue to be evaluated through the Industry Task Force process that could have an impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Issued March 2017): The new standard will require significant changes to the accounting and presentation of pension and OPEB costs at the plan sponsor (i.e., Exelon) level. This guidance requires plan sponsors to separate net periodic pension cost and net periodic OPEB cost (together, net benefit cost) into the service cost component and other components; service cost will be presented as part of income from operations and the other components will be classified outside of income from operations on the Consolidated Statements of Operations and Comprehensive Income. Additionally, service cost is the only component eligible for capitalization (whereas under current GAAP, all components of net benefit cost are eligible for capitalization).

Exelon is currently evaluating the impact of this standard on its consolidated financial statements, including coordinating with its industry group and advisors. Generation, ComEd, PECO, BGE, BSC, PHI, Pepco, DPL, ACE and PHISCO participate in Exelon s single employer plans and apply multi-employer accounting. Multi-employer accounting is not impacted by this standard, so there is no impact on Exelon s subsidiary financial statements.

The standard is effective January 1, 2018 and requires retrospective application for the presentation of the service cost component and the other components of net benefit cost and prospective application for the capitalization of only the service cost component of net benefit cost. Exelon will not early adopt this standard.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

arrangements. The guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only financing type lease liabilities (capital leases) are recognized in the balance sheet. This is expected to require significant changes to systems, processes and procedures in order to recognize and measure leases recorded on the balance sheet that are currently classified as operating leases. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. The accounting applied by a lessor is largely unchanged from that applied under current GAAP. The standard is effective January 1, 2019. Early adoption is permitted, however the Registrants do not expect to early adopt the standard. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. Refer to Note 24 Commitments and Contingencies of the Combined Notes to the Consolidated Financial Statements in the Exelon 2016 Form 10-K for additional information regarding operating leases.

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, for most debt instruments, 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 June 30, 2017. 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.

Clarifying the Definition of a Business (issued January 2017): Clarifies the definition of a business with the objective of addressing whether acquisitions should be accounted for as acquisitions of assets or as acquisitions of businesses. If substantially all the fair value of the assets acquired is concentrated in a single identifiable asset or a group of similar identifiable assets, the set of transferred assets and activities is not a business. If the fair value of the assets acquired is not concentrated in a single identifiable asset or a group of similar identifiable assets, then an entity must evaluate whether an input and a substantive process exist, which together significantly contribute to the ability to produce outputs. The standard also revises the definition of outputs to focus on goods and services to customers. The standard could result in more acquisitions being accounted for as asset acquisitions. The standard is effective January 1, 2018, with early adoption permitted, and will be applied prospectively.

Intra-Entity Transfers of Assets Other Than Inventory (Issued October 2016): Requires entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (current GAAP prohibits the recognition of current and deferred income taxes for an intra-entity

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

asset transfer until the asset has been sold to an outside party). The standard is effective January 1, 2018 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments (Issued August 2016) and Restricted Cash (Issued November 2016): In 2016, the FASB issued two standards impacting the Statement of Cash Flows. The first adds or clarifies guidance on the classification of certain cash receipts and payments on the statement of cash flows as follows: debt prepayment or extinguishment costs, settlement of zero-coupon bonds, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and bank-owned life insurance policies, distributions received from equity method investees, beneficial interest in securitization transactions, and the application of the predominance principle to separately identifiable cash flows. The second states that amounts generally described as restricted cash and restricted cash equivalents should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows (instead of being presented as cash flow activities). Exelon will adopt both standards on January 1, 2018 on a retrospective basis. Adoption of the second standard will result in a change in presentation of restricted cash on the face of the Statement of Cash Flows; otherwise the Registrants expect that adoption of the guidance will have insignificant impacts on the Registrants Consolidated Statements of Cash Flows and disclosures.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016): (i) Requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at amortized cost at the amount that would be received to sell the asset or paid to transfer the liability. The standard is effective January 1, 2018 with early adoption permitted. The guidance is required to be applied retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method).

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 June 30, 2017 and December 31, 2016, Exelon, Generation, BGE, PHI and ACE collectively consolidated seven and nine VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below).* As of June 30, 2017 and December 31, 2016, Exelon and Generation collectively had significant interests in seven and eight, respectively, 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).*

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Consolidated Variable Interest Entities

RSB BondCo LLC (BondCo) is a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property. BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. On April 3, 2017, the rate stabilization bonds were fully redeemed. During the three and six months ended June 30, 2017, BGE remitted $3 million and $22 million to BondCo, respectively, with all of the final $3 million remitted through June 30, 2017 after the bonds were fully redeemed. During the three and six months ended June 30, 2016, BGE remitted $21 million and $42 million to BondCo, respectively.

Upon the redemption of the bonds, BondCo no longer meets the definition of a variable interest entity and is removed from the list of consolidated VIEs noted below. However, BondCo will continue to be consolidated by BGE under the voting interest model.

During 2009, Constellation formed a retail gas group to enter into a collateralized gas supply agreement with a third-party gas supplier. Upon assessment, the retail gas group was determined to be a VIE because there was not sufficient equity to fund the group s activities without additional credit support and a $75 million parental guarantee provided by Generation. As the primary beneficiary, Generation consolidated the retail gas group. During the second quarter of 2017, the collateral structure was terminated with the third-party gas supplier except for the $75 million parental guarantee provided by Generation. Although the parental guarantee will remain, this is considered customary and reasonable for the unsecured position Generation has with the third-party gas supplier. As a result of the termination, the retail gas group no longer meets the definition of a VIE and is removed from the list of consolidated VIEs noted below. However, the retail gas group will continue to be consolidated by Generation under the voting interest model.

Exelon s, Generation s, PHI s and ACE s consolidated VIEs consist of:

- A group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,
- a group of companies formed by Generation to build, own and operate other generating facilities,
- certain retail power and gas companies for which Generation is the sole supplier of energy,
- CENG,
- 2015 ESA Investco, LLC, a company that holds an equity method investment in a distributed energy company, and
- 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 June 30, 2017 and December 31, 2016, ComEd, PECO, Pepco and DPL did not have any material consolidated VIEs.

As of June 30, 2017 and December 31, 2016, Exelon, Generation, PHI and ACE provided the following support to their respective consolidated VIEs:

Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance of the solar and wind power facilities and there is limited recourse to Generation related to certain solar and wind entities.

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

Generation provides approximately $30 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.

Generation provides operating and capital funding to the other generating facilities for ongoing construction, operations and maintenance and provides a parental guarantee of up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract in support of one of its other generating facilities.

Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 27 Related Party Transactions of the Exelon 2016 Form 10-K for additional information regarding Generation s and Exelon s transactions with CENG):

- under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,

- under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,

- 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 5 Regulatory Matters for additional details),

- Generation provided a $400 million loan to CENG. As of June 30, 2017, the remaining obligation is $324 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, Generation provides a guarantee of approximately $8 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 17 Commitments and Contingencies for more details), and

Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG s cash pooling agreement with its subsidiaries.

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In the case of ATF, proceeds from the sale of each series of transition bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three and six months ended June 30, 2017, ACE transferred $8 million and $27 million to ATF, respectively. During the three and six months ended June 30, 2016, ACE transferred $12 million and $26 million to ATF, respectively.

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

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

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at June 30, 2017 and December 31, 2016 are as follows:

	June 30, 2017				December 31, 2016				
	Exelon[(a)]	Generation	*Successor* PHI [(a)]	ACE	Exelon[(a)(b)]	Generation	BGE	*Successor* PHI [(a)]	ACE
Current assets	$ 512	$ 501	$ 11	$ 7	$ 954	$ 916	$ 23	$ 14	$ 9
Noncurrent assets	8,617	8,585	32	23	8,563	8,525	3	35	23
Total assets	$ 9,129	$ 9,086	$ 43	$ 30	$ 9,517	$ 9,441	$ 26	$ 49	$ 32
Current liabilities	$ 573	$ 535	$ 38	$ 34	$ 885	$ 802	$ 42	$ 42	$ 37
Noncurrent liabilities	2,723	2,640	83	74	2,713	2,612		101	89
Total liabilities	$ 3,296	$ 3,175	$ 121	$ 108	$ 3,598	$ 3,414	$ 42	$ 143	$ 126

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

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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 June 30, 2017 and December 31, 2016, these assets and liabilities primarily consisted of the following:

	June 30, 2017				December 31, 2016				
			Successor					*Successor*	
	Exelon [a]	Generation	PHI [a]	ACE	Exelon[a][b]	Generation	BGE	PHI [a]	ACE
Cash and cash equivalents	$ 68	$ 68	$	$	$ 150	$ 150	$	$	$
Restricted cash	55	48	7	7	59	27	23	9	9
Accounts receivable, net									
Customer	106	106			371	371			
Other	24	24			48	48			
Mark-to-market derivatives assets					31	31			
Inventory									
Materials and supplies	193	193			199	199			
Other current assets	38	34	4		50	44		5	
Total current assets	484	473	11	7	908	870	23	14	9
Property, plant and equipment, net	5,293	5,293			5,415	5,415			
Nuclear decommissioning trust funds	2,341	2,341			2,185	2,185			
Goodwill					47	47			
Mark-to-market derivative assets					23	23			
Other noncurrent assets	267	235	32	23	315	277	3	35	23
Total noncurrent assets	7,901	7,869	32	23	7,985	7,947	3	35	23
Total assets	$ 8,385	$ 8,342	$ 43	$ 30	$ 8,893	$ 8,817	$ 26	$ 49	$ 32
Long-term debt due within one year	$ 191	$ 154	$ 37	$ 33	$ 181	$ 99	$ 41	$ 40	$ 35
Accounts payable	80	80			269	269			
Accrued expenses	48	47	1	1	119	116	1	2	2
Mark-to-market derivative liabilities					60	60			
Unamortized energy contract liabilities	16	16			15	15			
Other current liabilities	5	5			30	30			
Total current liabilities	340	302	38	34	674	589	42	42	37
Long-term debt	616	533	83	74	641	540		101	89
Asset retirement obligations	1,954	1,954			1,904	1,904			
Pension obligation[c]					9	9			
Unamortized energy contract liabilities	13	13			22	22			
Other noncurrent liabilities	98	98			106	106			

Total noncurrent liabilities	2,681	2,598	83	74	2,682	2,581		101	89
Total liabilities	$ 3,021	$ 2,900	$ 121	$ 108	$ 3,356	$ 3,170	$ 42	$ 143	$ 126

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

(b) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

(c) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation s Consolidated Balance Sheets. See Note 13 Retirement Benefits for additional details.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 predominantly related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

The Registrants 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 and energy generating facilities for which Generation has concluded that consolidation is not required.

As of June 30, 2017 and December 31, 2016, Exelon and Generation had significant unconsolidated variable interests in seven and eight VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. The decrease in the number of unconsolidated VIEs is due to the sale of an equity investment in an energy generating facility. 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 $16 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 $16 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.

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of a distributed energy company, which is an unconsolidated VIE. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor contributed a total of $227 million of equity incrementally from inception through the first quarter of 2017 in proportion of their ownership interests. Generation and the tax equity investor provided a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC s obligation to make equity contributions to the distributed energy company. As all equity contributions were made as of the first quarter 2017, there is no further payment obligation under the parental guarantee.

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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:

June 30, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 641	$ 529	$ 1,170
Total liabilities[a]	64	229	293
Exelon s ownership interest in VIE[a]		268	268
Other ownership interests in VIE[a]	577	32	609
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		268	268
Contract intangible asset	9		9
Debt and payment guarantees			
Net assets pledged for Zion Station decommissioning[b]	6		6

December 31, 2016	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 638	$ 567	$ 1,205
Total liabilities[a]	215	287	502
Exelon s ownership interest in VIE[a]		248	248
Other ownership interests in VIE[a]	423	32	455
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		264	264
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning[b]	9		9

(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 $75 million and $113 million as of June 30, 2017 and December 31, 2016, respectively; offset by payables to ZionSolutions LLC of $69 million and $104 million as of June 30, 2017 and December 31, 2016, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 12 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.

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

Acquisition of James A. FitzPatrick Nuclear Generating Station (Exelon and Generation)

On March 31, 2017, Generation acquired the 838 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 $293 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $183 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. As of June 30, 2017, Generation had remitted purchase price consideration of $293 million (including $239 million of cash and $54 million of nuclear fuel) to and on behalf of Entergy.

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 as of June 30, 2017:

Cash paid for purchase price	$ 110
Cash paid for net cost reimbursement	129
Nuclear fuel transfer	54
Total consideration transferred	$ 293
Identifiable assets acquired and liabilities assumed	
Current assets	$ 58
Property, plant and equipment	278
Nuclear decommissioning trust funds	807
Other assets[(a)]	114
Total assets	$ 1,257
Current liabilities	$ 7
Asset retirement obligations	417
Pension and OPEB obligations	49
Deferred income taxes	144
Spent nuclear fuel obligation	110
Other liabilities	11
Total liabilities	$ 738
Total net identifiable assets, at fair value	$ 519
Bargain purchase gain (after-tax)	$ 226

(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 24-Commitments and Contingencies of the Exelon 2016 Form 10-K for additional background regarding SNF obligations to the DOE.

The after-tax bargain purchase gain of $226 million is included within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income and reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant.

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 to assess the fair value of certain assets acquired and liabilities assumed are preliminary. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date; however, Generation expects to finalize these amounts by the end of 2017. The significant assets and liabilities for which preliminary valuation amounts are recognized at June 30, 2017 include the fair value of the decommissioning ARO, pension and OPEB obligations and related deferred tax liabilities. Any changes to the fair value assessments may materially impact the purchase price allocation and the amount of the recorded bargain purchase gain.

For the three and six months ended June 30, 2017, Exelon and Generation incurred $16 million and $47 million, respectively, of merger and integration related costs which are included within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On March 23, 2016, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Purple Acquisition Corp., a wholly owned subsidiary of Exelon (Merger Sub) and Pepco Holdings, Inc. (PHI). As a result of that merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon s interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI s unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC.

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing 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 speaking, requires allocation of merger benefits proportionally across all the jurisdictions.

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware, New Jersey and Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in a total nominal cost of commitments of $513 million, excluding renewable generation commitments (approximately $444 million on a net present value basis amount, excluding renewable generation commitments and charitable contributions). These filings reflect agreements reached with certain parties to the merger proceedings in these jurisdictions. In 2016, the DPSC and NJBPU approved the amounts and allocations of the additional merger benefits for Delaware and New Jersey, respectively. On April 12, 2017, the MDPSC issued an order approving the amounts of the additional merger benefits for Maryland, but amending the proposed allocations of the benefits. The amended allocations do not have a material effect on any of the Registrants financial statements. No changes in commitment cost levels are required in the District of Columbia.

During the second quarter of 2017, Exelon finalized the application of $8 million funding for low- and moderate-income customers in the Pepco Maryland and DPL Maryland service territories. This resulted in an adjustment to merger commitment costs recorded at Exelon Corporate, Pepco, and DPL. Exelon Corporate recorded an increase of $8 million and Pepco and DPL recorded a decrease of $6 million and $2 million, respectively, in Operating and maintenance expense.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the acquisition date:

Description	Expected Payment Period	Pepco	DPL	ACE	*Successor* 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		$ 120	$ 84	$ 111	$ 315	$ 513

Pursuant to the orders approving the merger, Exelon made $73 million, $46 million and $49 million of equity contributions to Pepco, DPL and ACE, respectively, in the second quarter of 2016 to fund the after-tax amounts of the customer bill credit and the customer base rate credit commitments.

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.

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.

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 merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC s order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court s judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Court of Appeals of Maryland, which is the highest court in Maryland. On June 21, 2017, the Court of Appeals granted discretionary review of the January 27, 2017 decision by the Maryland Court of Special Appeals. The Maryland Court of Appeals will review the OPC argument that the MDPSC did not properly consider the acquisition premium paid to PHI shareholders under Maryland s merger approval standard and the Sierra Club s argument that the merger would harm the renewable and distributed generation markets. The two lower courts examining these issues rejected these arguments, which Exelon believes are without merit. The petitioners briefs were filed on July 31, 2017, and briefs of Exelon and the MDPSC are due on August 30, 2017. The case is set for oral argument in October 2017.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District of Columbia Office of People s Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC s March 23, 2016 order with the District of Columbia Court of Appeals. On July 20, 2017, the Court issued an opinion rejecting all of appellants arguments and affirming the Commission s decision approving the merger.

Accounting for the Merger Transaction

The total purchase price consideration of approximately $7.1 billion for the PHI Merger consisted of cash paid to PHI shareholders, cash paid for PHI preferred securities and cash paid for PHI stock-based compensation equity awards as follows:

(In millions of dollars, except per share data)	**Total Consideration**
Cash paid to PHI shareholders at $27.25 per share (254 million shares outstanding at March 23, 2016)	$ 6,933
Cash paid for PHI preferred stock	180
Cash paid for PHI stock-based compensation equity awards[(a)]	29
Total purchase price	$ 7,142

(a) PHI s unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI s remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

PHI shareholders received $27.25 of cash in exchange for each share of PHI common stock outstanding as of the effective date of the merger. In connection with the Merger Agreement, Exelon entered into a Subscription Agreement under which it purchased $180 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI prior to December 31, 2015. On March 23, 2016, the preferred securities were cancelled for no consideration to Exelon, and accordingly, the $180 million cash consideration previously paid to acquire the preferred securities was treated as purchase price consideration.

The preliminary valuations performed in the first quarter of 2016 were updated in the second, third, and fourth quarters of 2016. There were no adjustments to the purchase price allocation in the first quarter of 2017 and the purchase price allocation is now final.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Exelon applied push-down accounting to PHI, and accordingly, the PHI assets acquired and liabilities assumed were recorded at their estimated fair values on Exelon s and PHI s Consolidated Balance Sheets as of March 23, 2016, as follows:

Purchase Price Allocation [(a)]	
Current assets	$ 1,441
Property, plant and equipment	11,088
Regulatory assets	5,015
Other assets	248
Goodwill	4,005
Total assets	$ 21,797
Current liabilities	$ 2,752
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,447
Pension and OPEB obligations	821
Other liabilities	187
Total liabilities	$ 14,655
Total purchase price	$ 7,142

(a) Amounts shown reflect the final purchase price allocation and the correction of a reporting error identified and corrected in the second quarter of 2016. The error had resulted in a gross up of certain assets and liabilities related to legacy PHI intercompany and income tax receivable and payable balances.

On its successor financial statements, PHI has recorded, beginning March 24, 2016, Membership interest equity of $7.2 billion, which is greater than the total $7.1 billion purchase price, reflecting the impact of a $59 million deferred tax liability recorded only at Exelon Corporate to reflect unitary state income tax consequences of the merger.

The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled $4.0 billion, which was recognized as goodwill by PHI and Exelon at the acquisition date, reflecting the value associated with enhancing Exelon s regulated utility portfolio of businesses, including the ability to leverage experience and best practices across the utilities and the opportunities for synergies. For purposes of future required impairment assessments, the goodwill has been preliminarily assigned to PHI s reportable units Pepco, DPL and ACE in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. None of this goodwill is expected to be tax deductible.

Immediately following closing of the merger, $235 million of net assets included in the table above associated with PHI s unregulated business interests were distributed by PHI to Exelon. Exelon contributed $163 million of such net assets to Generation.

The fair values of PHI 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, future market prices and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

Through its wholly owned rate regulated utility subsidiaries, most of PHI s assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. In applying the acquisition method of accounting, for regulated assets and liabilities included in rate base or otherwise earning a return (primarily property, plant and equipment and regulatory assets earning a return), no fair value adjustments were recorded as historical cost is viewed as a reasonable proxy for fair value.

Fair value adjustments were applied to the historical cost bases of other assets and liabilities subject to rate regulation but not earning a return (including debt instruments and pension and OPEB obligations). In these instances, a corresponding offsetting regulatory asset or liability was also established, as the underlying utility asset and liability amounts are recoverable from or refundable to customers at historical cost (and not at fair value) through the rate setting process. Similar treatment was applied for fair value adjustments to record intangible assets and liabilities, such as for electricity and gas energy supply contracts as further described below. Regulatory assets and liabilities established to offset fair value adjustments are amortized in amounts and over time frames consistent with the realization or settlement of the fair value adjustments, with no impact on reported net income. See Note 5 Regulatory Matters for additional information regarding the fair value of regulatory assets and liabilities established by Exelon and PHI.

Fair value adjustments were recorded at Exelon and PHI for the difference between the contract price and the market price of electricity and gas energy supply contracts of PHI s wholly owned rate regulated utility subsidiaries. These adjustments are intangible assets and liabilities classified as unamortized energy contracts on Exelon s and PHI s Consolidated Balance Sheets as of June 30, 2017. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchase power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

As mentioned, under cost-of-service rate regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. Historical cost information therefore is the most relevant presentation for the financial statements of PHI s rate regulated utility subsidiary registrants, Pepco, DPL and ACE. As such, Exelon and PHI did not push-down the application of acquisition accounting to PHI s utility registrants, and therefore the financial statements of Pepco, DPL and ACE do not reflect the revaluation of any assets and liabilities.

The current impact of PHI, including its unregulated businesses, on Exelon s Consolidated Statements of Operations and Comprehensive Income includes:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
Operating revenues	$ 1,113	$ 1,112	$ 2,332	$ 1,219
Net income (loss)	61	52	202	(262)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three and six months ended June 30, 2017 and 2016, the Registrants have recognized costs to achieve the PHI acquisition as follows:

Acquisition, Integration and Financing Costs[a]	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Exelon[b]	$ 8	$ 1	$ 17	$ 103
Generation	4	4	13	20
ComEd[c]		1	1	(7)
PECO	1	1	2	2
BGE[d]	1	(5)	2	(4)
Pepco[e]	1	(4)	2	23
DPL[f]			(7)	16
ACE	1	2	2	15

	Successor				*Predecessor*
Acquisition, Integration and Financing Costs[a]	**Three Months Ended June 30, 2017**	**Three Months Ended June 30, 2016**	**Six Months Ended June 30, 2017**	**March 24, 2016 to June 30, 2016**	**January 1, 2016 to March 23, 2016**
PHI[g]	$ 2	$ (1)	$ (2)	$ 55	$ 29

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense. Costs do not include merger commitments discussed above.

(b) Reflects costs (benefits) recorded at Exelon related to financing, including mark-to-market activity on forward-starting interest rate swaps.

(c) For the six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, incurred at ComEd that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.

(d) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $6 million incurred at BGE that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.

(e) For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $9 million incurred at Pepco that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.

(f) For the six months ended June 30, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. For the three and six months ended June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $3 million incurred at DPL that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.

(g) For the six months ended June 30, 2017, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million incurred at PHI that have been deferred and recorded as a regulatory asset for anticipated recovery. For the three months ended June 30, 2016 and the Successor period March 24, 2016 to June 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $12 million incurred at PHI that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon as if the merger with PHI had taken place on January 1, 2015. The unaudited pro forma information was calculated after applying Exelon s accounting policies and adjusting PHI s results to reflect purchase accounting adjustments.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Three Months Ended June 30, 2016[(a)]	Six Months Ended June 30, 2016[(a)]	Year Ended December 31, 2016[(b)]
Total operating revenues	$ 6,910	$ 15,466	$ 32,342
Net income attributable to common shareholders	268	845	1,562
Basic earnings per share	$ 0.29	$ 0.92	$ 1.69
Diluted earnings per share	0.29	0.91	1.69

(a) The amounts above include adjustments for non-recurring costs directly related to the merger of $1 million and $641 million for the three and six months ended June 30, 2016, respectively, and intercompany revenue of $170 million for the six months ended June 30, 2016.
(b) The amounts above include adjustments for non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for the year ended December 31, 2016.

Asset Divestitures (Exelon, Generation, PHI and Pepco)

EGTP, a Delaware limited liability company, was formed in 2014 with the purpose of financing a portfolio of assets comprised of two combined-cycle gas turbines (CCGTs) and three peaking/simple cycle facilities consisting of approximately 3.4 GW of generation capacity in ERCOT North and Houston Zones. EGTP is an indirect wholly owned subsidiary of Exelon and Generation. Each of the aforementioned facilities is held through a wholly owned direct subsidiary of EGTP. EGTP also owns two equity method investments in shared facility companies. EGTP, its direct parent and its wholly owned subsidiaries secured a nonrecourse senior secured term loan facility, a revolving loan facility and certain commodity and interest rate swaps.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP, including the revolving credit facility. See Note 10 Debt and Credit Agreements for details regarding the nonrecourse debt associated with EGTP. As a result, certain EGTP assets and liabilities were classified as held for sale at their respective fair values less costs to sell and included in the other current assets and other current liabilities balances on Exelon s and Generation s Consolidated Balance Sheets. At June 30, 2017, a $418 million pre-tax impairment loss was recorded within Operating and maintenance expense on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. See Note 6 Impairment of Long-Lived Assets for further information.

On April 21, 2016, Generation completed the sale of the retired New Boston generating site, located in Boston, Massachusetts, resulting in a pre-tax gain of approximately $32 million.

On May 2, 2016, Pepco completed the sale of the New York Avenue land parcel, located in Washington D.C., resulting in a pre-tax gain of approximately $8 million at Pepco. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in the Exelon and PHI Consolidated Statements of Operations and Comprehensive Income.

5. Regulatory Matters (All Registrants)

Except for the matters noted below, the disclosures set forth in Note 3 Regulatory Matters of the Exelon 2016 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

Distribution Formula Rate (Exelon and ComEd). On April 13, 2017, ComEd filed its annual distribution formula rate with the ICC pursuant to EIMA. The filing establishes the revenue requirement used to set the rates that will take effect in January 2018 after the ICC s review and approval, which is due by December 2017. The revenue requirement requested is based on 2016 actual costs plus projected 2017 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2016 to the actual costs incurred that year. ComEd s 2017 filing request includes a total increase to the revenue requirement of $96 million, reflecting an increase of $78 million for the initial revenue requirement for 2017 and an increase of $18 million related to the annual reconciliation for 2016. The revenue requirement for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.47% inclusive of an allowed ROE of 8.40%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2016 provided for a weighted average debt and equity return on distribution rate base of 6.45% inclusive of an allowed ROE of 8.34%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 6 basis points. See table below for ComEd s regulatory assets associated with its distribution formula rate. For additional information on ComEd s distribution formula rate filings see Note 3 Regulatory Matters of the Exelon 2016 Form 10-K.

On December 6, 2016, the ICC issued a final order approving the 2016 distribution formula rate, which included a total increase to the revenue requirement of $127 million, reflecting an increase of $134 million for the initial revenue requirement for 2016 and a decrease of $7 million related to the annual reconciliation for 2015. On December 20, 2016, the ICC granted ComEd s and other parties joint application for rehearing on the impact that changing ComEd s OSHA recordable rate for 2014 and 2015 had on the revenue requirement approved in this order. On March 22, 2017, the ICC issued an order approving ComEd s proposal to reduce the 2016 revenue requirement by $18 million, which was reflected in customer rates in April 2017.

Illinois Future Energy Jobs Act (Exelon, Generation, and ComEd).

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA was effective June 1, 2017, and includes, among other provisions, (1) a Zero Emission Standard (ZES) providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd s electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd s customer rates exceeds specified limits, (6) revisions to the existing net metering statute and (7) support for low income rooftop and community solar programs.

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria.

On July 21, 2017, Exelon and others submitted comments on the IPA s draft Procurement Plan. The IPA filed the plan with the ICC on July 31, 2017. The ICC has 45 days to approve the plan. Once the plan is approved by the ICC, bidders interested in participating in the procurement process will have 14 days to submit the required eligibility information and become qualified bidders. Generation s Clinton and Quad Cities nuclear plants will participate in the procurement process. Winning bidders will contract directly with Illinois utilities, including ComEd, for 10-year terms extending through May 31, 2027. The ZEC price will be based upon the current social cost of carbon as determined by the Federal government and is initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Utilities will be required to purchase an amount of ZECs equivalent to 16% of the actual amount of electricity delivered in 2014, subject to specified annual caps. For the initial delivery year, June 1, 2017 May 31, 2018, the targeted procurement of ZECs, after applying the cap, is set at $235 million (ComEd s share is approximately $170 million). For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices

ComEd currently expects to enter into contracts with winning bidders in the fourth quarter 2017, at which time it will begin recording an associated obligation and expense for the procurement of ZEC s. Winning bidders will be entitled to compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA.

ComEd will recover all costs associated with purchasing ZECs through a new 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 and recorded a regulatory liability of $22 million as of June 30, 2017 for revenues recorded in advance of incurring expenses.

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 court granted the motions to dismiss and also dismissed the motions for preliminary injunction. On July 17, 2017, the plaintiffs appealed the court s decisions to the U.S. Court of Appeals for the Seventh Circuit. 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, financial positions and cash flows.

See Note 7 Early Nuclear 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.

ComEd Electric Distribution Rates

FEJA extends the sunset date for ComEd s performance-based electric distribution formula rate from 2019 to the end of 2022, allows ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allows ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd will revise its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation filed in 2018 for the 2017 calendar year. Elimination of the ROE collar effectively offsets the favorable or unfavorable impacts to Operating 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 first quarter 2017. As of June 30, 2017, ComEd recorded an increase to Operating revenues and its electric distribution services costs regulatory asset of approximately $36 million for this change.

FEJA requires ComEd to make non-recoverable contributions to low income energy assistance programs of $10 million per year for 5 years as long as the electric distribution formula rate remains in effect. With the exception of these contributions, ComEd will recover from customers, subject to certain caps explained below, the costs it incurs pursuant to FEJA either through its electric distribution formula rate or other recovery mechanisms.

Energy Efficiency

Prior to FEJA, Illinois law required ComEd to implement cost-effective energy efficiency measures and, for a 10-year period ending May 31, 2018, cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers.

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $250 million to $400 million annually from 2017 through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017. On June 30, 2017, ComEd filed its 2018 2021 energy efficiency plan with the ICC, which must be approved no later than September 14, 2017.

FEJA allows ComEd to cancel its existing energy efficiency rate rider and replace it with an energy efficiency formula rate, and to defer energy efficiency costs (except for any voltage optimization costs which will be recovered through the electric distribution formula rate) as a separate regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life, as approved by the ICC, of the related energy efficiency measures. ComEd will earn a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd s electric distribution formula rate. Beginning January 1, 2018 through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd s cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd will be required to file an update to its energy efficiency formula rate on or before June 1 each year, with resulting rates effective in January of the following year. The annual update will be based on projected current year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes. The update will also include a reconciliation of any differences between the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs and actual year-end energy efficiency regulatory asset balances less any related deferred income taxes. ComEd will record a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation.

ComEd cancelled its existing energy efficiency rate rider effective June 2, 2017. ComEd will perform a reconciliation of revenues and costs incurred through the cancellation date and issue a one-time credit on retail customers bills for any over-recoveries. As of June 30, 2017, ComEd s over-recoveries associated with its former energy efficiency rate rider were $88 million, which were reflected in Current regulatory liabilities on Exelon s and ComEd s Consolidated Balance Sheets as ComEd expects to provide the one-time credit to customers within the next twelve months.

Initial Energy Efficiency Formula Rate Filing

On June 9, 2017, ComEd filed its new initial energy efficiency formula rate with the ICC pursuant to FEJA. The filing establishes the formula under which energy efficiency rates will be calculated going forward and the revenue requirement used to set the initial rates for the period October 1, 2017 through December 31, 2017 subject to the ICC s review and approval, which is required by August 23, 2017. The initial revenue requirement is based on projected costs and projected PJM capacity revenues for the period from June 1, 2017 through December 31, 2017, and projected year-end 2017 energy efficiency regulatory asset balances (less any related deferred income taxes). ComEd requested an initial decrease in revenue requirement of $7 million reflecting higher projected PJM capacity revenues compared to projected energy efficiency costs and provides for a weighted average debt and equity return of 6.47% inclusive of an allowed ROE of 8.40%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2017 will be included in ComEd s 2018 energy efficiency formula rate filing and reflected in customer rates beginning January 2019. As of June 30, 2017, under the new formula rate, Exelon and ComEd deferred $21 million of energy efficiency costs as a regulatory asset. ComEd also recorded a regulatory liability of $2 million for the 2017 energy efficiency formula rate annual reconciliation.

2017 Energy Efficiency Formula Rate Filing

On June 30, 2017, ComEd filed its annual energy efficiency formula rate with the ICC pursuant to FEJA. The filing establishes the revenue requirement used to set rates that will take effect in January 2018 after the ICC s review and approval, which is due no later than September 14, 2017. The revenue requirement for 2018 is based on projected 2018 energy efficiency costs and PJM capacity revenues, and year-end 2018 energy efficiency regulatory asset balances (less any related deferred income taxes). In its 2017 filing ComEd requested a total increase to the revenue requirement of $12 million and provides for a weighted average debt and equity return of 6.47% inclusive of an allowed ROE of 8.40%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2018 will be included in ComEd s 2019 energy efficiency formula rate filing, and reflected in customer rates beginning January 2020.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of RECs. FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. FEJA also requires ComEd to use RPS collections to fund utility job training and workforce development programs in the amounts of $10 million in each of the years 2017, 2021, and 2025. ComEd recorded a $10 million and $20 million current and non-current liability, respectively, as of June 30, 2017 associated with this obligation. ComEd will recover all costs associated with purchasing RECs and funding utility job training and workforce development programs through a new RPS rate rider that provides for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd s retail customers in subsequent periods with interest. The first reconciliation and true-up for RECs will occur in 2021 and cover revenues and costs for the four year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up. ComEd began billing its retail customers under its new RPS rate rider on June 1, 2017 and recorded a related regulatory asset of $19 million as of June 30, 2017. Any over-recovered RPS costs will be deposited into a separate interest bearing bank account pursuant to FEJA, which will be classified as Restricted cash on Exelon s and ComEd s Consolidated Balance Sheets.

Customer Rate Increase Limitations

FEJA includes provisions intended to limit the average impact on ComEd customer rates for recovery of costs incurred under FEJA as follows: (1) for a typical ComEd residential customer, the average impact must be less than $0.25 cents per month, (2) for nonresidential customers with a peak demand less than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois commercial retail customers during 2015, and (3) for nonresidential customers with a peak demand greater than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois industrial retail customers during 2015.

On June 30, 2017, ComEd submitted a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW. Such projections indicate that customer rate impacts will not exceed the limitations set by FEJA discussed below. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the first four years, ComEd is required to decrease costs associated with FEJA investments, including reductions to ZEC contract quantities. If the projected residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations during the last six years, ComEd is required to demonstrate how it will reduce FEJA investments to ensure compliance. If the actual residential customer or nonresidential customer with a peak demand less than 10 MW rate increase exceeds the limitations for any one year, ComEd is required to submit a corrective action plan to decrease future year costs to reduce customer rates to ensure future compliance. If the actual residential customer or nonresidential customer rate exceeds the limitations for two consecutive years, ComEd can offer to credit customers for amounts billed in excess of the limitations or ComEd can terminate FEJA investments. If ComEd chooses to terminate FEJA investments, the ICC shall order termination of ZEC contracts and further initiate proceedings to reduce energy efficiency savings goals and terminate support for low-income rooftop and community solar programs. ComEd is allowed to fully recover all costs incurred as of and up to the date of the programs termination.

For the energy efficiency formula, ComEd records a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. For

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

the other rate riders be established under FEJA, ComEd records a regulatory asset or liability for any differences between revenues and incurred expenses.

Renewable Energy Resources (Exelon and ComEd). In accordance with legislation in effect on December 31, 2016, the IPA s Procurement Plans include the procurement of cost-effective renewable energy resources in amounts that equal or exceed a minimum target percentage of the total electricity that each electric utility supplies to its eligible retail customers. The June 1, 2016 target renewable energy resources obligation for the utilities was at least 11.5%. This obligation increases by at least 1.5% each year thereafter to an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth by Illinois legislation. As of June 30, 2017, ComEd had purchased renewable energy resources or equivalents, such as RECs, in accordance with the IPA Procurement Plan. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates.

In accordance with FEJA that took effect on June 1, 2017, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA shall develop a long term renewable resources procurement plan (LT Plan). The RPS target percentages for the overall service territory have not changed through June 1, 2025 although FEJA extended the 25% RPS target to delivery years after 2025. Currently, each RES and each utility is responsible for the renewable resource obligation of the customers it supplies power for. Over time, this will change and the utility will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by the utility for the retail load the utility supplies and for 50% of the retail customer load supplied by Retail Electric Suppliers in the utility service territory on February 28, 2017. Utility procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). Through PECO s PAPUC approved DSP Programs, PECO procures electric supply for its default electric customers through PAPUC approved competitive procurements.

On March 17, 2016, PECO filed its fourth DSP Program with the PAPUC proposing a 24-month term from June 1, 2017 through May 31, 2019, in compliance with electric generation procurement guidelines set forth in Act 129. On December 8, 2016, the PAPUC approved the fourth DSP Program for the modified 48-month term and deferred CAP Shopping to another proceeding. OCA and Low Income Advocates subsequently filed a Petition for Reconsideration and Clarification related to CAP Shopping. On March 16, 2017, the PAPUC granted reconsideration and consolidated the proceeding with the DSP II docket, which includes the pending CAP Shopping plan that would allow low-income CAP customers to purchase their generation supply from EGSs. PAPUC referred the consolidated proceedings to the Office of Administrative Law Judge for hearing and decision.

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which provided the PAPUC authority to approve the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC s implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving or replacing aging infrastructure. The PAPUC approved PECO s petition for its proposed electric DSIC and LTIIP on October 22, 2015 for spending of $275 million over a 5 year period through 2020. The

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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PAPUC approved PECO s petition for its proposed modified gas LTIIP on June 14, 2017 for spending of $762 million over a 10 year period through 2022.

Maryland Regulatory Matters

2017 Maryland Electric Distribution Rates (Exelon, PHI and Pepco). On March 24, 2017, Pepco filed an application with the MDPSC requesting an increase of $69 million based on a ROE of 10.1%. The application includes a request for an income tax adjustment to reflect full normalization of removal costs associated with pre-1981 property, which accounts for $18 million of the requested increase. Pepco expects a decision in the matter in the fourth quarter of 2017, but cannot predict how much of the requested rate increase the MDPSC will approve or if it will approve the requested income tax adjustment.

2017 Maryland Electric Distribution 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 based on a requested ROE of 10.1%. DPL expects a decision on the matter in the first quarter of 2018. DPL cannot predict how much of the requested increase the MDPSC will approve.

2016 Maryland Electric Distribution Rates (Exelon, PHI and DPL). On February 15, 2017, the MDPSC approved an increase in DPL electric distribution rates of $38 million based on a ROE of 9.6%. The new rates became effective for services rendered on or after February 15, 2017. The MDPSC also denied DPL s request to continue its Grid Resiliency Program, through which DPL proposed to invest $4.6 million a year for two years to improve priority feeders and install single-phase reclosing fuse technology. The final order did not result in the recognition of any incremental regulatory assets or liabilities.

Cash Working Capital Order (Exelon and BGE). On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE s request to recover its cash working capital (CWC) requirement for its Provider of Last Resort service, also known as Standard Offer Service (SOS), as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover all of its SOS-related costs. The Administrative Charge is now comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which is an adder to the utility s SOS rate to act as a proxy for retail suppliers costs. The Commission accepted BGE s positions on recovery of CWC and pass-through recovery of BGE s actual uncollectibles and incremental costs. The order also grants BGE a return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE s next rate case. On December 16, 2016, MDPSC Staff requested clarification concerning the amount of return on the SOS awarded to BGE and on December 19, 2016, the residential consumer advocate sought rehearing of the return awarded. On January 24, 2017, the MDPSC issued an order denying the MDPSC Staff request for clarification and the residential consumer advocate request for rehearing. On February 22, 2017, the residential consumer advocate filed an appeal of the MDPSC s orders with the Circuit Court for Baltimore City. The residential consumer advocate filed its Memorandum on Appeal on June 5, 2017 and subsequent Reply Memoranda were filed by BGE and the MDPSC on July 7, 2017 and July 12, 2017, respectively. Oral arguments are scheduled for August 7, 2017. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of June 30, 2017 and December 31, 2016, the balance of BGE s regulatory asset was $225 million and $230 million, respectively, representing incremental program deployment costs. The current quarter balance of $225 million consists of three major components, including $137 million of unamortized incremental deployment costs of the AMI program, $56 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. The balance as of June 30, 2017 reflects the impact of the cost disallowances and adjustments in BGE s 2015 electric and natural gas distribution rate case. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being recovered through rates and amortized to expense over a 10 year period, while the post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC. A return on the regulatory asset is currently included in rates, except for the $56 million portion representing the unamortized cost of the retired non-AMI meters and a $32 million portion related to post-test year incremental program deployment costs.

As a combined result of the MDPSC orders in BGE s 2015 electric and natural gas distribution rate case, BGE recorded a $52 million charge in June 2016 to Operating and maintenance expense in Exelon s and BGE s Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets and reclassified $56 million of non-AMI plant costs from Property, plant and equipment, net to Regulatory assets on Exelon s and BGE s Consolidated Balance Sheets. For further information, see Note 3 Regulatory Matters of the Exelon 2016 Form 10-K.

Delaware Regulatory Matters

Gas Cost Rates (Exelon, PHI and DPL). DPL makes an annual GCR filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. In August 2016, DPL made its 2016-2017 GCR filing. The rates proposed in the 2016-2017 GCR filing resulted in a GCR increase of approximately 14%. On September 20, 2016, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2016, subject to refund and pending final DPSC approval. A settlement agreement was reached by all parties. On April 20, 2017, the DPSC issued an order which approved the settlement agreement and made the rates approved as final effective November 1, 2016.

2016 Electric and Natural Gas Distribution Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million (which was updated to $60 million on March 8, 2017) and $22 million, respectively, based on a requested ROE of 10.6%. Delaware law allowed DPL to put into effect $2.5 million of each of the rate increases effective July 16, 2016. On December 17, 2016, the DPSC approved an additional $29.6 million in electric distribution rates and an additional $10.4 million in natural gas distribution rates effective December 17, 2016, subject to refund based on the final DPSC orders.

On March 8, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate, Delaware Electric Users Group and the DPSC Staff in its electric distribution rate proceeding, which provides for an increase in DPL annual electric distribution base rates of $31.5 million based on an ROE of 9.7% compared to the $32.1 million increase previously put into effect. On May 23, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective June 1, 2017. Pursuant to the settlement agreement, no refund of the interim rates put into effect on July 16, 2016 and December 17, 2016 (as discussed above) is required.

On April 6, 2017, DPL entered into a settlement agreement with the Division of the Public Advocate and the DPSC Staff in its natural gas distribution rate proceeding, which provides for an increase in DPL annual natural gas distribution base rates of $4.9 million based on an ROE of 9.7%. The settlement agreement also provides that DPL will refund amounts collected under the temporary rates effective July 16, 2016 and December 17, 2016 (as discussed above) in excess of the $4.9 million, and that the new rates will be effective within thirty days of DPSC approval of the settlement agreement. On June 6, 2017, the DPSC issued an order approving the settlement agreement, with the new rates effective July 1, 2017. Pursuant to the settlement agreement, a rate refund plus interest of approximately $5 million will be issued to customers beginning in August 2017 for which a regulatory liability has been recorded as of June 30, 2017.

District of Columbia Regulatory Matters

2016 Electric Distribution Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, as updated to approximately $77 million on February 1, 2017, based on a requested ROE of 10.6%.

On July 25, 2017, the DCPSC issued an order granting Pepco an increase to its annual electric distribution base rates of $36.9 million based on an ROE of 9.5%. The new rates will be effective August 15, 2017. In its decision, the DCPSC ordered that the $25.6 million customer rate credit created as a result of the Exelon and PHI merger will be provided primarily to residential customers and some small commercial customers to offset the impact of this increase until that amount has been exhausted, which is expected to take approximately two years. Additionally, the Commission is holding approximately $6 million to $7 million of the customer rate credit for use toward a possible new class of customers for certain senior citizens and disabled persons. The DCPSC also held that Pepco s bill stabilization adjustment, which decouples distribution revenues from utility customers from the amount of electricity delivered, will continue to be in place and that no refund of previously collected funds is required. Parties have 30 days from the date of the order to file for reconsideration with the DCPSC.

District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco). The District of Columbia government enacted on an emergency basis (effective May 17, 2017) and thereafter on a permanent basis (effective July 11, 2017) legislation to amend the Electric Company Infrastructure Improvement Financing Act of 2014 (as amended) (the Infrastructure Improvement Financing Act) to authorize the District of Columbia Power Line Undergrounding (DC PLUG) initiative, a projected six year, $500 million project to place underground some of the District of Columbia s most outage-prone power lines with $250 million of the project costs funded by Pepco and $250 million funded by the District of Columbia.

The $250 million of project costs funded by Pepco will be recovered through a volumetric surcharge on the electric bill of substantially all of Pepco s customers in the District of Columbia. Pepco will earn a return on these project costs.

The $250 million of project costs funded by the District of Columbia will come from two sources. Project costs of $187.5 million will be funded through a charge assessed on Pepco by the District of Columbia; Pepco will recover this charge from customers through a volumetric distribution rider. The remaining costs up to $62.5 million are to be funded by the existing capital projects program of the District Department of Transportation (DDOT). Ownership and responsibility for the operation and maintenance of all the assets funded by the District of Columbia will be transferred to Pepco for a nominal amount upon completion. Pepco will not recover or earn a return on the cost of the assets transferred to it by the District of Columbia.

In accordance with the Infrastructure Improvement Financing Act, Pepco filed an application for approval of the first two-year portion of the DC PLUG initiative (the First Biennial Plan) on July 3, 2017. After the initial application, Pepco will be required to make two updated applications, one every two years until the project is completed. Pepco anticipates that the DCPSC will issue an order approving the First Biennial Plan in the fourth quarter of 2017. Upon the issuance of a DCPSC order approving the First Biennial Plan, Pepco will become obligated to pay $187.5 million to the District of Columbia over the six year project term, at which time it will record an obligation and offsetting regulatory asset.

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

New Jersey Regulatory Matters

2017 Electric Distribution Rates (Exelon, PHI and ACE). On March 30, 2017, ACE submitted an application with the NJBPU to increase its electric distribution rates by approximately $70 million (before New Jersey sales and use tax), which was updated to $72.6 million on July 14, 2017, based upon a requested ROE of 10.1%. The application also requests approval of a rate surcharge mechanism called the System Renewal Recovery Charge, which would permit more timely recovery of certain costs associated with reliability and system renewal-related capital investments. ACE currently expects a decision in this matter in the first quarter of 2018, but cannot predict how much of the requested increase the NJBPU will approve.

2016 Electric Distribution Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, which, among other things, provided that a determination on ACE s grid resiliency program, PowerAhead, would be separated into a phase II of the rate proceeding and decided at a later date. PowerAhead includes capital investments to enhance the resiliency of the system through improvements focused on improving the distribution system s ability to withstand major storm events. A stipulation of settlement with respect to the PowerAhead program (the PowerAhead Stipulation) was approved by the NJBPU on May 31, 2017. As adopted, the PowerAhead program includes an approved investment level of $79 million to be recovered through the cost recovery mechanism described in the PowerAhead Stipulation. The NJBPU order adopting the PowerAhead Stipulation was effective on June 10, 2017.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE s long-term power purchase contracts with the non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE s uncollectible accounts. As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate decrease of approximately $29 million (revised to approximately $32 million in April 2017, based upon an update for actuals through March 2017), including New Jersey sales and use tax. On May 31, 2017, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate decrease of approximately $32 million, effective June 1, 2017. The rate decrease was placed into effect provisionally, subject to a review by NJBPU and the Division of Rate Counsel of the final underlying costs for reasonableness and prudence. This rate decrease will have no effect on ACE s operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism. The matter is pending at the NJBPU.

New York Regulatory Matters

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of which is the 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 New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increase in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified three plants eligible for the ZEC program: the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy s execution of the required contract for the FitzPatrick facility. On March 31, 2017, Generation closed on the acquisition of FitzPatrick. Generation is currently recognizing revenue for the sale of New York ZECs in the month following generation when the ZECs are transferred to NYSERDA. For the three months ended June 30, 2017 Generation has recognized $73 million of ZEC revenue.

Several parties filed with the NYPSC requests for rehearing or reconsideration of the CES. Generation and CENG also filed a request for clarification, or in the alternative limited rehearing, that the condition limiting the duration of the program beyond the first tranche be limited to the eligibility of the FitzPatrick plant only and have no bearing on Ginna or Nine Mile Point s eligibility for the full 12-year duration. On December 15, 2016, the NYPSC approved Generation s and CENG s petition to clarify this condition and denied all petitions for rehearing of the CES. Parties had until mid-April to appeal to New York State court the denials of the requests for rehearing. A Petition seeking to invalidate the ZEC program was filed in New York State court by certain environmental groups and other parties on November 30, 2016, and amended on January 13, 2017, arguing that the NYPSC 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. The motion is pending.

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. Briefing has been completed on the motion to dismiss, and oral argument was held on March 29, 2017. The motion to intervene has been granted. On July 25, 2017, the court granted both motions to dismiss. Plaintiffs are expected to appeal.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 7 Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point. See Note 4 Mergers, Acquisitions and Dispositions for additional information on Generation s acquisition of FitzPatrick.

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). In November 2014, in response to a petition filed by Ginna Nuclear Power Plant (Ginna) regarding the possible retirement of Ginna, the NYPSC directed Ginna and Rochester Gas & Electric Company (RG&E) to negotiate a Reliability Support Services Agreement (RSSA) to support the continued operation of Ginna to maintain the reliability of the RG&E transmission grid for a specified period of time. During 2015 and 2016, Ginna and RG&E made filings with the NYPSC and FERC for their approval of the proposed RSSA. Although the RSSA was still subject to regulatory approvals, on April 1, 2015, Ginna began delivering the power and capacity from the Ginna plant into the ISO-NY consistent with the technical provisions of the RSSA.

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

On March 22, 2016, Ginna submitted a compliance filing with FERC with revisions to the RSSA requested by FERC. On April 8, 2016, FERC accepted the compliance filing and on April 20, 2016, the NYPSC accepted the revised RSSA with a term expiring on March 31, 2017. In April 2016, Generation began recognizing revenue based on the final approved pricing contained in the RSSA and also recognized a one-time revenue adjustment of approximately $101 million representing the net cumulative previously unrecognized amount of revenue retroactive from the April 1, 2015 effective date through March 31, 2016. A 49.99% portion of the one-time adjustment was removed from Generation s results of operations as a result of the noncontrolling interests in CENG.

The RSSA required Ginna to continue operating through the RSSA term. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the CES. As stated previously, on November 18, 2016 the required contract with NYSERDA was executed by Generation and CENG for Ginna. Upon the expiry of the RSSA on March 31, 2017, Ginna was required to make refund payments of $20 million to RG&E related to capital expenditures. Ginna paid RGE the $20 million in June 2017. Additionally, the provisions of the RSSA provided for a one-time payment of $12 million to be paid from RGE to Ginna at the end of the contract. This $12 million was recognized in revenue as of March 31, 2017. RGE paid the $12 million to Ginna in May 2017. Subject to prevailing over any administrative or legal challenges, it is expected the CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 7-Early Nuclear Plant Retirements for further information regarding the impacts of a decision to early retire one or more nuclear plants.

Federal Regulatory Matters

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

			2017		
Annual Transmission Filings[(a)]	**ComEd**	**BGE**	**Pepco**	**DPL**	**ACE**
Initial revenue requirement increase	$ 44	$ 31	$ 5	$ 6	$ 20
Annual reconciliation (decrease) increase	(33)	3	15	8	22
Dedicated facilities decrease [(b)]		(8)			
Total revenue requirement increase	$ 11	$ 26	$ 20	$ 14	$ 42
Allowed return on rate base [(c)]	8.43%	7.47%	7.92%	7.16%	8.02%
Allowed ROE [(d)]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2017, subject to review by the FERC and other parties, which is due by fourth quarter 2017.
(b) BGE s transmission revenues include a FERC approved dedicated facilities charge to recover the costs of providing transmission service to specifically designated load by BGE.
(c) Represents the weighted average debt and equity return on transmission rate bases.
(d) As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

For additional information regarding transmission formula rate filings see Note 3 Regulatory Matters of the Exelon 2016 Form 10-K.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

PJM Transmission Rate Design and Operating Agreements (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO, BGE, Pepco, DPL and ACE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM s current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit for review of the decision.

In August 2009, the court issued its decision affirming the FERC s order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants, filed a proposed Settlement with FERC. If the Settlement is approved, 50% of the costs of the 500 kV and above facilities approved by the PJM Board on or before February 1, 2013 will be socialized across PJM and 50% will be allocated according to a formula that calculates the flows on the transmission facilities. Each state that is a party in this proceeding either signed, or did not oppose, the settlement. The Settlement is opposed by a number of merchant transmission owners and New York load-serving entities. The Settlement includes provisions for monthly credits or charges that are expected to be mostly refunded or recovered through customer rates over a 10-year period based on negotiated numbers for charges prior to January 1, 2016.

Exelon expects that the Settlement will not have a material impact on the results of operations, cash flows and financial position of Generation, ComEd, PECO, BGE, Pepco, DPL or ACE. The Settlement is subject to approval by FERC.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs (Exelon and Generation). PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon s view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

On January 9, 2017, the Electric Power Supply Association (EPSA) filed two requests with FERC: one seeking to amend a prior complaint against PJM and another seeking expedited action on a pending NYISO compliance filing in an existing proceeding. Both filings allege that the relevant MOPR should be expanded to also apply to existing resources receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon has filed protests at FERC in response to each filing, arguing generally that ZEC payments provide compensation for an environmental attribute that is distinct from the energy and capacity sold in the FERC-jurisdictional markets, and therefore, are no different than other renewable support programs like the PTC and RPS that have generally not been subject to a MOPR. However, if successful, for Generation s facilities in NYISO and PJM expected to receive ZEC compensation (Quad Cities, Ginna, Nine Mile Point and FitzPatrick), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in those auctions and thus no longer receiving capacity revenues during the respective ZEC programs. Any such mitigation of these generating resources could have a material effect on Exelon s and Generation s future cash flows and results of operations. The timing of FERC s decision with respect to both proceedings is currently unknown and the outcome of these matters is currently uncertain.

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 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. In addition, Generation continues to work with MDE and other Federal and Maryland state agencies to conduct and fund an additional sediment and nutrient monitoring study.

On April 21, 2016, Exelon and 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 amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license. Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon s and Generation s results of operations and financial position through an increase in capital expenditures and operating costs. As of June 30, 2017, $29 million of direct costs associated with Conowingo licensing efforts have been capitalized. See Note 3 Regulatory Matters of the Exelon 2016 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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As a result of applying the acquisition method of accounting and pushing it down to the consolidated financial statements of PHI, certain regulatory assets and liabilities were established at Exelon and PHI to offset the impacts of fair valuing the acquired assets and liabilities assumed which are subject to regulatory recovery. In total, Exelon and PHI recorded a net $2.4 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting. See Note 4 Mergers, Acquisitions and Dispositions for additional information.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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 June 30, 2017 and December 31, 2016. For additional information on the specific regulatory assets and liabilities, refer to Note 3 Regulatory Matters of the Exelon 2016 Form 10-K.

					Successor			
June 30, 2017	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory assets								
Pension and other postretirement benefits [a]	$ 4,086	$	$	$	$	$	$	$
Deferred income taxes [b]	2,091	76	1,645	100	270	176	41	53
AMI programs	679	163	43	225	248	167	81	
Under-recovered distribution service costs [c]	239	239						
Energy efficiency costs	19	19						
Debt costs	117	39	1	7	77	16	8	6
Fair value of long-term debt	782				645			
Fair value of PHI s unamortized energy contracts	918				918			
Severance	3			3				
Asset retirement obligations	119	84	23	12				
MGP remediation costs	289	266	23					
Under-recovered uncollectible accounts	55	55						
Renewable energy	258	256			2		1	1
Energy and transmission programs [d][e][f][g][h][i]	69	8	1	21	39	6	6	27
Deferred storm costs	34				34	10	6	18
Electric generation-related regulatory asset	5			5				
Energy efficiency and demand response programs	590		1	271	318	236	82	
Merger integration costs [j][k]	32			7	25	12	13	
Under-recovered revenue decoupling [l]	74			35	39	31	8	
COPCO acquisition adjustment	6				6		6	
Workers compensation and long-term disability cost	34				34	34		
Vacation accrual	47		22		25		15	10
Securitized stranded costs	108				108			108
CAP arrearage	10		10					
Removal costs	500				500	138	95	268
Renewable portfolio standards costs	19	19						
Other	55	8	9	6	32	21	8	4
Total regulatory assets	11,238	1,232	1,778	692	3,320	847	370	495
Less: current portion	1,293	182	46	197	605	165	71	89
Total non-current regulatory assets	$ 9,945	$ 1,050	$ 1,732	$ 495	$ 2,715	$ 682	$ 299	$ 406

					Successor			
June 30, 2017	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory liabilities								
Other postretirement benefits	$ 43	$	$	$	$	$	$	$
Nuclear decommissioning	2,870	2,364	506					

Removal costs	1,592	1,332		129	131	18	113	
Deferred rent	38				38			
Energy efficiency and demand response programs	128	88	39		1	1		
DLC program costs	8		8					
Electric distribution tax repairs	59		59					
Gas distribution tax repairs	16		16					
Energy and transmission programs [d][e][f][g][h][i]	123	40	61		22	2	12	8
Rate stabilization deferral	3			3				
Zero emission credit costs	22	22						
Other	70	8	10	25	27	1	13	12
Total regulatory liabilities	4,972	3,854	699	157	219	22	138	20
Less: current portion	574	269	155	67	68	5	43	20
Total non-current regulatory liabilities	$ 4,398	$ 3,585	$ 544	$ 90	$ 151	$ 17	$ 95	$

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

December 31, 2016	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits [(a)]	$ 4,162	$	$	$	$	$	$	$
Deferred income taxes [(b)]	2,016	75	1,583	98	260	171	38	51
AMI programs	701	164	49	230	258	174	84	
Under-recovered distribution service costs [(c)]	188	188						
Debt costs	124	42	1	7	81	17	9	6
Fair value of long-term debt	812				671			
Fair value of PHI s unamortized energy contracts	1,085				1,085			
Severance	5			5				
Asset retirement obligations	111	76	23	12				
MGP remediation costs	305	278	26	1				
Under-recovered uncollectible accounts	56	56						
Renewable energy	260	258			2			2
Energy and transmission programs [(d)(e)(f)(g)(h)(i)]	89	23		38	28	6	5	17
Deferred storm costs	36			1	35	12	5	18
Electric generation-related regulatory asset	10			10				
Rate stabilization deferral	7			7				
Energy efficiency and demand response programs	621		1	285	335	250	85	
Merger integration costs [(j)(k)]	25			10	15	11	4	
Under-recovered revenue decoupling [(l)]	27			3	24	21	3	
COPCO acquisition adjustment	8				8		8	
Workers compensation and long-term disability costs	34				34	34		
Vacation accrual	31		7		24		14	10
Securitized stranded costs	138				138			138
CAP arrearage	11		11					
Removal costs	477				477	134	88	255
Other	49	7	9	5	29	22	5	4
Total regulatory assets	11,388	1,167	1,710	712	3,504	852	348	501
Less: current portion	1,342	190	29	208	653	162	59	96
Total non-current regulatory assets	$ 10,046	$ 977	$ 1,681	$ 504	$ 2,851	$ 690	$ 289	$ 405

December 31, 2016	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 47	$	$	$	$	$	$	$
Nuclear decommissioning	2,607	2,169	438					
Removal costs	1,601	1,324		141	136	18	118	
Deferred rent	39				39			
Energy efficiency and demand response programs	185	141	41		3	3		
DLC program costs	8		8					
Electric distribution tax repairs	76		76					
Gas distribution tax repairs	20		20					
Energy and transmission programs [(d)(e)(f)(g)(h)(i)]	134	60	56		18	8	5	5

Other	72	4	5	19	41	2	17	20
Total regulatory liabilities	4,789	3,698	644	160	237	31	140	25
Less: current portion	602	329	127	50	79	11	43	25
Total non-current regulatory liabilities	$ 4,187	$ 3,369	$ 517	$ 110	$ 158	$ 20	$ 97	$

(a) As of June 30, 2017 and December 31, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of $1,025 million and $995 million, respectively, as a result of the PHI Merger related to unrecognized costs that are probable of regulatory recovery. The regulatory assets are amortized over periods from 3 to 15 years, depending on the underlying component. Pepco, DPL and ACE are currently recovering these costs through base rates. Pepco, DPL and ACE are not earning a return on the recovery of these costs in base rates.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) As of June 30, 2017, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $41 million, $33 million, $22 million and $20 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $38 million, $31 million, $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively. On December 13, 2016, BGE filed with FERC to begin recovering these existing and any similar future regulatory assets through its transmission formula rate. On May 9, 2017, FERC accepted BGE s filing and made effective BGE s proposed modifications to its transmission formula rate, subject to refund and further Commission order. ComEd, Pepco, DPL, and ACE are expected to make similar filings with FERC and other parties in subsequent periods.

(c) As of June 30, 2017, ComEd s regulatory asset of $239 million was comprised of $184 million for the 2015 2017 annual reconciliations and $55 million related to significant one-time events including $14 million of deferred storm costs, $9 million of Constellation and PHI merger and integration related costs, $3 million of emerald ash borer costs, and $29 million of smart meter related costs. As of December 31, 2016, ComEd s regulatory asset of $188 million was comprised of $134 million for the 2015 and 2016 annual reconciliations and $54 million related to significant one-time events, including $20 million of deferred storm costs and $11 million of Constellation and PHI merger and integration related costs, and $23 million of smart meter related costs. See Note 4 Merger, Acquisitions, and Dispositions of the Exelon 2016 Form 10-K for further information.

(d) As of June 30, 2017, ComEd s regulatory asset of $8 million reflects Constellation merger and integration costs to be recovered upon FERC approval. As of June 30, 2017, ComEd s regulatory liability of $40 million included $8 million related to over-recovered energy costs and $32 million associated with revenues received for renewable energy requirements. As of December 31, 2016, ComEd s regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC approved formula rate and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016, ComEd s regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements.

(e) As of June 30, 2017, PECO s regulatory asset of $1 million related to under-recovered electric transmission costs. As of June 30, 2017, PECO s regulatory liability of $61 million included $36 million related to over-recovered costs under the DSP program, $16 million related to the over-recovered natural gas costs under the PGC and $9 million related to over-recovered non-bypassable transmission service charges. As of December 31, 2016, PECO s regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to the over-recovered electric transmission costs.

(f) As of June 30, 2017, BGE s regulatory asset of $21 million included $10 million related to under-recovered electric energy costs, $5 million related to under-recovered natural gas costs, $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate and $2 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2016, BGE s regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $3 million of under-recovered natural gas costs.

(g) As of June 30, 2017, Pepco s regulatory asset of $6 million included $2 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of June 30, 2017, Pepco s regulatory liability of $2 million related to over-recovered electric energy costs. As of December 31, 2016, Pepco s regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016, Pepco s regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs.

(h) As of June 30, 2017, DPL s regulatory asset of $6 million related to under-recovered electric energy costs. As of June 30, 2017, DPL s regulatory liability of $12 million included $10 million of over-recovered electric energy costs and $2 million of over-recovered gas cost. As of December 31, 2016, DPL s regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of December 31, 2016, DPL s regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs.

(i) As of June 30, 2017, ACE s regulatory asset of $27 million included $11 million of transmission costs recoverable through its FERC approved formula rate and $16 million of under-recovered electric energy costs. As of June 30, 2017, ACE s regulatory liability of $8 million related to over-recovered electric energy costs. As of December 31, 2016, ACE s regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016, ACE s regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs.

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

(j) As of June 30, 2017 and December 31, 2016, BGE s regulatory asset of $7 million and $10 million, respectively, included $6 million of previously incurred PHI acquisition costs as authorized by the June 2016 rate case order.

(k) As of June 30, 2017 and December 31, 2016, Pepco s regulatory asset of $12 million and $11 million, respectively, represents previously incurred PHI acquisition costs authorized for recovery by the November 2016 Maryland distribution rate case order. As of June 30, 2017, DPL s regulatory asset of $13 million represents previously incurred PHI acquisition costs, including $4 million authorized for recovery by the February 2017 Maryland distribution rate case order, $6 million authorized for recovery by the May 2017 Delaware electric distribution rate case order, and $3 million expected to be recovered in electric and gas distribution rates in the Delaware service territory. As of December 31, 2016, DPL s regulatory asset of $4 million represents previously incurred PHI acquisition costs expected to be recovered in distribution rates in the Maryland service territory.

(l) Represents the electric and natural gas distribution costs recoverable from customers under BGE s decoupling mechanism. As of June 30, 2017, BGE had a regulatory asset of $24 million related to under-recovered electric revenue decoupling and $11 million related to under-recovered natural gas revenue decoupling. As of December 31, 2016, BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling.

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
June 30, 2017	$ 71	$ 6	$	$ 55	$ 10	$ 6	$ 4	$

	Exelon	ComEd[(a)]	PECO	BGE[(b)]	PHI	Pepco[(c)]	DPL[(c)]	ACE
December 31, 2016	$ 72	$ 5	$	$ 57	$ 10	$ 6	$ 4	$

(a) Reflects ComEd s unrecognized equity returns earned for ratemaking purposes on its under-recovered distribution services costs regulatory assets.

(b) BGE s authorized amounts capitalized for ratemaking purposes 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

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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 June 30, 2017 and December 31, 2016.

As of June 30, 2017	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Purchased receivables[b]	$ 304	$ 85	$ 73	$ 53	$ 93	$ 61	$ 10	$ 22
Allowance for uncollectible accounts[a]	(31)	(12)	(5)	(3)	(11)	(6)	(2)	(3)
Purchased receivables, net	$ 273	$ 73	$ 68	$ 50	$ 82	$ 55	$ 8	$ 19

As of December 31, 2016	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Purchased receivables[b]	$ 313	$ 87	$ 72	$ 59	$ 95	$ 63	$ 10	$ 22
Allowance for uncollectible accounts[a]	(37)	(14)	(6)	(4)	(13)	(7)	(2)	(4)
Purchased receivables, net	$ 276	$ 73	$ 66	$ 55	$ 82	$ 56	$ 8	$ 18

(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.

(b) Pepco s electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 2% depending on customer class. Pepco s electric POR program in the District of Columbia included a discount on purchased receivables ranging from 0% to 6% through April 6, 2017 and 0% to 2% effective April 7, 2017, depending on customer class. DPL s electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 1% through May 31, 2017 and 0% to 4% effective June 1, 2017, depending on customer class.

6. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. EGTP s operating cash flows have been negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries, the proceeds from which will first be used to pay the administrative costs of the sale, the normal and ordinary costs of operating the plants and repayment of the secured debt of EGTP. As a result, certain EGTP s assets and liabilities were classified as held for sale at their respective fair values less costs to sell and included in the other current assets and other current liabilities balances on Exelon s and Generation s Consolidated Balance Sheets at June 30, 2017. Additionally, a pre-tax impairment charge of $418 million was recorded in June 2017 within Operating and maintenance expense on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. See Note 4 Mergers, Acquisitions and Dispositions for additional information.

During the first quarter of 2016, significant changes in Generation s intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its upstream subsidiary CEU Holdings, LLC (as described in Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 4 Mergers, Acquisitions and Dispositions of the Exelon 2016 Form 10-K for further information.

In the second quarter of 2016, updates to the Company s long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than their carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result of the fair value analysis, long-lived assets held and used with a carrying amount of approximately $60 million were written down to their fair value of $24 million and a pre-tax impairment charge of $36 million was recorded during the second quarter in Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

Also in the second quarter of 2016, updates to the Company s long-term view, as described above, in conjunction with the previous decision to early retire the Clinton and Quad Cities nuclear facilities in Illinois suggested that the carrying value of our Midwest asset group may be impaired. Generation completed a comprehensive review of the estimated undiscounted future cash flows of the Midwest asset group and no impairment charge was required.

Like-Kind Exchange Transaction (Exelon)

In June 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon Corporation, entered into transactions pursuant to which UII invested in coal-fired generating station leases (Headleases) with the Municipal Electric Authority of Georgia (MEAG). The generating stations were leased back to MEAG as part of the transactions (Leases).

On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon s Consolidated Statements of Operations and Comprehensive Income. See Note 11 Income Taxes for additional information.

7. Early Nuclear Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation s nuclear plants. Factors that will continue to affect the economic value of Generation s nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, 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 nuclear plant, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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any co-owner requirements and stipulations, and decommissioning trust fund requirements, 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, where applicable, and just prior to its next scheduled nuclear refueling outage.

In 2015 and 2016, Generation identified the Clinton, Quad Cities, Ginna, Nine Mile Point, and Three Mile Island (TMI) nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. PSEG has also recently made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. As previously disclosed, Exelon and Generation have committed to cease operation of the Oyster Creek nuclear plant by the end of 2019.

The TMI nuclear plant did not clear in the May 2017 PJM capacity auction for the 2020-2021 planning year and will not receive capacity revenue for that period, 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.

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. The current NRC license for TMI expires in 2034. Generation is proceeding with the market and regulatory notifications that must be made to shut down the plant, including filing of a deactivation notice with PJM on May 30, 2017 and notification to the NRC on June 20, 2017. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

In the second quarter of 2017, as a result of the plant retirement decision of TMI, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $71 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of TMI 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. Exelon s and Generation s second quarter 2017 results include an incremental $37 million of pre-tax expense for these items. Please refer to Note 12 Nuclear Decommissioning for additional detail on changes to the nuclear decommissioning ARO balances resulting from the early retirement of TMI.

Income statement expense (pre-tax)	**June 30, 2017**
Depreciation and amortization	
Accelerated depreciation[(a)]	$ 35
Accelerated Nuclear Fuel amortization	2
Total	$ 37

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

Based on insufficient capacity auction results and the lack of progress on Illinois energy legislation, on June 2, 2016, Generation announced a decision to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively. With the passage of the Illinois ZES on December 7, 2016, and subject to prevailing over any related administrative or legal challenges, Generation reversed this decision and revised the expected economic useful lives for both facilities; 2027 for Clinton and 2032 for Quad Cities. Refer to Note 5 Regulatory Matters for additional discussion on the Illinois ZES.

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Exelon s and Generation s 2016 results included a net incremental $714 million of total pre-tax expense associated with the initial early retirement decision for Clinton and Quad Cities, as summarized in the table below.

Income statement expense (pre-tax)	**Q2 2016**	**Q3 2016**	**Q4 2016**	**YTD 2016**
Depreciation and amortization				
Accelerated depreciation[(a)]	$ 115	$ 344	$ 253	$ 712
Accelerated Nuclear Fuel amortization	9	28	23	60
Operating and maintenance				
One time charges[(b)]	141	5	(120)	26
ARO accretion, net of contractual offset[(c)]		2		2
Contractual offset for ARC depreciation[(c)]	(14)	(41)	(31)	(86)
Total	$ 251	$ 338	$ 125	$ 714

(a) Reflects incremental accelerated depreciation of plant assets, including any ARC, for the period June 2, 2016, through December 6, 2016.
(b) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and construction work-in-progress (CWIP) impairments.
(c) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

In New York, the Ginna, Nine Mile Point, and Generation s recently acquired FitzPatrick nuclear plant also faced significant economic challenges and risk of retirement before the end of each unit s respective operating license period (2029 for Ginna and Nine Mile Point Unit 1, 2046 for Nine Mile Point Unit 2, and 2034 for FitzPatrick). On August 1, 2016, the NYPSC issued an order adopting the CES that, subject to prevailing over any administrative or legal challenges, would allow Ginna, Nine Mile Point, and FitzPatrick to continue to operate at least through the life of the program (March 31, 2029). The assumed useful life for depreciation purposes for each facility is through the end of their current operating licenses. Ginna most recently operated under an RSSA which expired March 31, 2017 and has filed the required notice with the NYPSC of its intent to continue operating beyond the expiry of the RSSA. Refer to Note 4 Mergers, Acquisitions and Dispositions for additional information on Generation s acquisition of FitzPatrick and Note 5 Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

Assuming the successful implementation of the Illinois ZES and the New York CES and the continued effectiveness of these programs, 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 (and now including the newly acquired FitzPatrick) 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 position.

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

Fair Value of Financial Liabilities Recorded at the Carrying Amount

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 June 30, 2017 and December 31, 2016:

Exelon

	June 30, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,757	$	$ 1,757	$	$ 1,757
Long-term debt (including amounts due within one year)[(a)]	33,934		33,460	1,956	35,416
Long-term debt to financing trusts[(b)]	641			693	693
SNF obligation	1,139		830		830

	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 1,267	$	$ 1,267	$	$ 1,267
Long-term debt (including amounts due within one year)[(a)]	34,005	1,113	31,741	1,959	34,813
Long-term debt to financing trusts[(b)]	641			667	667
SNF obligation	1,024		732		732

Generation

	June 30, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 716	$	$ 716	$	$ 716
Long-term debt (including amounts due within one year)[(a)]	9,754		8,061	1,661	9,722
SNF obligation	1,139		830		830

	December 31, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 699	$	$ 699	$	$ 699
Long-term debt (including amounts due within one year)[(a)]	9,241		7,482	1,670	9,152
SNF obligation	1,024		732		732

ComEd

	June 30, 2017				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 389	$	$ 389	$	$ 389
Long-term debt (including amounts due within one year)[a]	7,036		7,728		7,728
Long-term debt to financing trusts[b]	205			223	223

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		December 31, 2016			
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 7,033	$	$ 7,585	$	$ 7,585
Long-term debt to financing trusts[b]	205			215	215

PECO

		June 30, 2017			
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,580	$	$ 2,834	$	$ 2,834
Long-term debt to financing trusts	184			199	199

		December 31, 2016			
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,580	$	$ 2,794	$	$ 2,794
Long-term debt to financing trusts	184			192	192

BGE

		June 30, 2017			
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 85	$	$ 85	$	$ 85
Long-term debt (including amounts due within one year)[a]	2,282		2,497		2,497
Long-term debt to financing trusts[b]	252			271	271

		December 31, 2016			
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 45	$	$ 45	$	$ 45
Long-term debt (including amounts due within one year)[a]	2,322		2,467		2,467
Long-term debt to financing trusts[b]	252			260	260

PHI (Successor)

		June 30, 2017			
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 67	$	$ 67	$	$ 67
Long-term debt (including amounts due within one year)[a]	5,952		5,707	295	6,002

	December 31, 2016				
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 522	$	$ 522	$	$ 522
Long-term debt (including amounts due within one year)[(a)]	5,898		5,520	289	5,809

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Pepco

			June 30, 2017		
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,545	$	$ 3,065	$ 9	$ 3,074

			December 31, 2016		
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 23	$	$ 23	$	$ 23
Long-term debt (including amounts due within one year)[a]	2,349		2,788	8	2,796

DPL

			June 30, 2017		
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 25	$	$ 25	$	$ 25
Long-term debt (including amounts due within one year)[a]	1,326		1,398		1,398

			December 31, 2016		
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 1,340	$	$ 1,383	$	$ 1,383

ACE

			June 30, 2017		
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 42	$	$ 42	$	$ 42
Long-term debt (including amounts due within one year)[a]	1,138		980	286	1,266

			December 31, 2016		
	Carrying		Fair Value		
	Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 1,155	$	$ 1,007	$ 280	$ 1,287

(a) Includes unamortized debt issuance costs which are not fair valued of $185 million, $53 million, $44 million, $15 million, $14 million, $6 million, $33 million, $11 million, and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of June 30, 2017. Includes unamortized debt issuance costs of $200 million, $64 million, $46 million, $15 million, $15 million, $2 million,

$30 million, $11 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2016.

(b) Includes unamortized debt issuance costs which are not fair valued of $7 million, $1 million, and $6 million for Exelon, ComEd and BGE, respectively, as of June 30, 2017 and December 31, 2016.

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1) and short-term borrowings (Level 2). The Registrants carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

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Long-Term Debt. The fair value amounts of Exelon s taxable debt securities (Level 2) and private placement taxable debt securities (Level 3) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the utility sector with similar credit ratings in both the primary and secondary market, across the Registrants debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. Due to low trading volume of private placement debt, qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3. The fair value of Exelon s equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation s and Pepco s non-government-backed fixed rate nonrecourse debt (Level 3) is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles. Given the low trading volume in the nonrecourse debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation s government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate financing debt resets on a monthly or quarterly basis and the carrying value approximates fair value (Level 2). When trading data is available on variable rate financing debt, the fair value is based on market and quoted prices for its own and other nonrecourse debt with similar risk profiles (Level 2). Generation, Pepco, DPL and ACE also have tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above. Variable rate tax-exempt debt (Level 2) resets on a regular basis and the carrying value approximates fair value.

SNF Obligation. The carrying amount of Generation s SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation s nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation s discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2030. This amount also includes $110 million as of June 30, 2017 for the fair value of the one-time fee obligation associated with closing of the FitzPatrick acquisition on March 31, 2017. The fair value was determined using a similar methodology, however the New York Power Authority s (NYPA) discount rate is used in place of Generation s given the contractual right to reimbursement from NYPA for the obligation; see Note 4 Mergers, Acquisitions and Dispositions for additional information on Generation s acquisition of FitzPatrick.

Long-Term Debt to Financing Trusts. Exelon s long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.

- Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.

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

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no material transfers between Level 1 and Level 2 during the six months ended June 30, 2017 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.

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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 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 June 30, 2017 and December 31, 2016:

	Generation					Exelon				
As of June 30, 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]	$ 29	$	$	$	$ 29	$ 257	$	$	$	$ 257
NDT fund investments										
Cash equivalents[b]	117	67			184	117	67			184
Equities	3,980	717		2,104	6,801	3,980	717		2,104	6,801
Fixed income										
Corporate debt		1,656	255		1,911		1,656	255		1,911
U.S. Treasury and agencies	1,767	32			1,799	1,767	32			1,799
Foreign governments		51			51		51			51
State and municipal debt		232			232		232			232
Other[c]		46		502	548		46		502	548
Fixed income subtotal	1,767	2,017	255	502	4,541	1,767	2,017	255	502	4,541
Middle market lending			428	78	506			428	78	506
Private equity				197	197				197	197
Real estate				441	441				441	441
NDT fund investments subtotal[d]	5,864	2,801	683	3,322	12,670	5,864	2,801	683	3,322	12,670
Pledged assets for Zion Station decommissioning										
Cash equivalents	21				21	21				21
Middle market lending			21	33	54			21	33	54
Pledged assets for Zion Station decommissioning subtotal[e]	21		21	33	75	21		21	33	75
Rabbi trust investments										
Cash equivalents	5				5	78				78
Mutual funds	22				22	54				54
Fixed income							13			13
Life insurance contracts		20			20		67	21		88
Rabbi trust investments subtotal	27	20			47	132	80	21		233
Commodity derivative assets										
Economic hedges	632	2,698	1,604		4,934	632	2,698	1,604		4,934
Proprietary trading	3	47	31		81	3	47	31		81
Effect of netting and allocation of collateral[f] [g]	(627)	(2,343)	(767)		(3,737)	(627)	(2,343)	(767)		(3,737)
Commodity derivative assets subtotal	8	402	868		1,278	8	402	868		1,278

Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments							11			11
Economic hedges		17			17		17			17
Proprietary trading	3	1			4	3	1			4
Effect of netting and allocation of collateral	(3)	(10)			(13)	(3)	(10)			(13)
Interest rate and foreign currency derivative assets subtotal		8			8		19			19
Other investments			41		41			41		41
Total assets	5,949	3,231	1,613	3,355	14,148	6,282	3,302	1,634	3,355	14,573

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					Exelon				
As of June 30, 2017	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Liabilities										
Commodity derivative liabilities										
Economic hedges	(697)	(2,691)	(1,151)		(4,539)	(697)	(2,691)	(1,407)		(4,795)
Proprietary trading	(4)	(48)	(25)		(77)	(4)	(48)	(25)		(77)
Effect of netting and allocation of collateral[(f) (g)]	698	2,627	897		4,222	698	2,627	897		4,222
Commodity derivative liabilities subtotal	(3)	(112)	(279)		(394)	(3)	(112)	(535)		(650)
Interest rate and foreign currency derivative liabilities										
Economic hedges		(20)			(20)		(20)			(20)
Proprietary trading	(4)				(4)	(4)				(4)
Effect of netting and allocation of collateral	3	10			13	3	10			13
Interest rate and foreign currency derivative liabilities subtotal	(1)	(10)			(11)	(1)	(10)			(11)
Deferred compensation obligation		(33)			(33)		(131)			(131)
Total liabilities	(4)	(155)	(279)		(438)	(4)	(253)	(535)		(792)
Total net assets	$ 5,945	$ 3,076	$ 1,334	$ 3,355	$ 13,710	$ 6,278	$ 3,049	$ 1,099	$ 3,355	$ 13,781

	Generation					Exelon				
As of December 31, 2016	**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)]	$ 39	$	$	$	$ 39	$ 373	$	$	$	$ 373
NDT fund investments										
Cash equivalents[(b)]	110	19			129	110	19			129
Equities	3,551	452		2,011	6,014	3,551	452		2,011	6,014
Fixed income										
Corporate debt		1,554	250		1,804		1,554	250		1,804
U.S. Treasury and agencies	1,291	29			1,320	1,291	29			1,320
Foreign governments		37			37		37			37
State and municipal debt		264			264		264			264
Other[(c)]		59		493	552		59		493	552
Fixed income subtotal	1,291	1,943	250	493	3,977	1,291	1,943	250	493	3,977
Middle market lending			427	71	498			427	71	498
Private equity				148	148				148	148
Real estate				326	326				326	326

NDT fund investments subtotal[d]	4,952	2,414	677	3,049	11,092	4,952	2,414	677	3,049	11,092
Pledged assets for Zion Station decommissioning										
Cash equivalents	11				11	11				11
Equities		2			2		2			2
Fixed Income U.S. Treasury and agencies	16	1			17	16	1			17
Middle market lending			19	64	83			19	64	83
Pledged assets for Zion Station decommissioning subtotal[e]	27	3	19	64	113	27	3	19	64	113
Rabbi trust investments										
Cash equivalents	2				2	74				74
Mutual funds	19				19	50				50
Fixed income							16			16
Life insurance contracts		18			18		64	20		84
Rabbi trust investments subtotal	21	18			39	124	80	20		224

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					**Exelon**				
As of December 31, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Commodity derivative assets										
Economic hedges	1,356	2,505	1,229		5,090	1,358	2,505	1,229		5,092
Proprietary trading	3	50	23		76	3	50	23		76
Effect of netting and allocation of collateral[(f) (g)]	(1,162)	(2,142)	(481)		(3,785)	(1,164)	(2,142)	(481)		(3,787)
Commodity derivative assets subtotal	197	413	771		1,381	197	413	771		1,381
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments							16			16
Economic hedges		28			28		28			28
Proprietary trading	3	2			5	3	2			5
Effect of netting and allocation of collateral	(2)	(19)			(21)	(2)	(19)			(21)
Interest rate and foreign currency derivative assets subtotal	1	11			12	1	27			28
Other investments			42		42			42		42
Total assets	5,237	2,859	1,509	3,113	12,718	5,674	2,937	1,529	3,113	13,253
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,267)	(2,378)	(794)		(4,439)	(1,267)	(2,378)	(1,052)		(4,697)
Proprietary trading	(3)	(50)	(26)		(79)	(3)	(50)	(26)		(79)
Effect of netting and allocation of collateral[(f) (g)]	1,233	2,339	542		4,114	1,233	2,339	542		4,114
Commodity derivative liabilities subtotal	(37)	(89)	(278)		(404)	(37)	(89)	(536)		(662)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(10)			(10)		(10)			(10)
Economic hedges		(21)			(21)		(21)			(21)
Proprietary trading	(4)				(4)	(4)				(4)
Effect of netting and allocation of collateral	4	19			23	4	19			23
Interest rate and foreign currency derivative liabilities subtotal		(12)			(12)		(12)			(12)
Deferred compensation obligation		(34)			(34)		(136)			(136)
Total liabilities	(37)	(135)	(278)		(450)	(37)	(237)	(536)		(810)
Total net assets	$ 5,200	$ 2,724	$ 1,231	$ 3,113	$ 12,268	$ 5,637	$ 2,700	$ 993	$ 3,113	$ 12,443

(a)

Generation excludes cash of $238 million and $252 million at June 30, 2017 and December 31, 2016 and restricted cash of $164 million and $157 million at June 30, 2017 and December 31, 2016. Exelon excludes cash of $353 million and $360 million at June 30, 2017 and December 31, 2016 and restricted cash of $203 million and $180 million at June 30, 2017 and December 31, 2016 and includes long term restricted cash of $25 million at June 30, 2017 and December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) Includes $48 million and $29 million of cash received from outstanding repurchase agreements at June 30, 2017 and December 31, 2016, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $(1) million and $(2) million, which have a total notional amount of $771 million and $933 million at June 30, 2017 and December 31, 2016, 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 $29 million and $31 million at June 30, 2017 and December 31, 2016, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(e) Excludes net assets of less than $1 million at June 30, 2017 and December 31, 2016. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(f) Collateral posted/(received) from counterparties totaled $71 million, $284 million and $130 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 30, 2017. Collateral posted/(received) from counterparties, net of collateral paid to counterparties, totaled $71 million, $197 million and $61 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2016.

(g) Of the collateral posted/(received), $84 million represents variation margin on the exchanges as of June 30, 2017. Of the collateral posted/(received), $(158) million represents variation margin on the exchanges as of December 31, 2016.

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 June 30, 2017 and December 31, 2016:

	ComEd				PECO				BGE			
As of June 30, 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)]	$	$	$	$	$ 28	$	$	$ 28	$ 5	$	$	$ 5
Rabbi trust investments												
Mutual funds					7			7	5			5
Life insurance contracts						10		10				
Rabbi trust investments subtotal					7	10		17	5			5
Total assets					35	10		45	10			10
Liabilities												
Deferred compensation obligation		(7)		(7)		(10)		(10)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(256)	(256)								
Total liabilities		(7)	(256)	(263)		(10)		(10)		(4)		(4)
Total net assets (liabilities)	$	$ (7)	$ (256)	$ (263)	$ 35	$	$	$ 35	$ 10	$ (4)	$	$ 6

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	ComEd				PECO				BGE			
As of December 31, 2016	**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)]	$ 20	$	$	$ 20	$ 45	$	$	$ 45	$ 36	$	$	$ 36
Rabbi trust investments												
Mutual funds					7			7	4			4
Life insurance contracts						10		10				
Rabbi trust investments subtotal					7	10		17	4			4
Total assets	20			20	52	10		62	40			40
Liabilities												
Deferred compensation obligation		(8)		(8)		(11)		(11)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(258)	(258)								
Total liabilities		(8)	(258)	(266)		(11)		(11)		(4)		(4)
Total net assets (liabilities)	$ 20	$ (8)	$ (258)	$ (246)	$ 52	$ (1)	$	$ 51	$ 40	$ (4)	$	$ 36

(a) ComEd excludes cash of $39 million and $36 million at June 30, 2017 and December 31, 2016 and restricted cash of $12 million and $2 million at June 30, 2017 and December 31, 2016. PECO excludes cash of $21 million and $22 million at June 30, 2017 and December 31, 2016. BGE excludes cash of $12 million and $13 million at June 30, 2017 and December 31, 2016 and restricted cash of $3 million at June 30, 2017 and includes long term restricted cash of $2 million at June 30, 2017 and December 31, 2016, which is reported in other deferred debits on the balance sheet.

(b) The Level 3 balance consists of the current and noncurrent liability of $19 million and $237 million, respectively, at June 30, 2017, and $19 million and $239 million, respectively, at December 31, 2016, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on PHI s, Pepco s, DPL s and ACE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2017 and December 31, 2016:

	Successor							
	As of June 30, 2017				As of December 31, 2016			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 189	$	$	$ 189	$ 217	$	$	$ 217
Mark-to-market derivative assets[(b)]					2			2
Effect of netting and allocation of collateral					(2)			(2)
Mark-to-market derivative assets subtotal								
Rabbi trust investments								
Cash equivalents	73			73	73			73
Fixed income		13		13		16		16
Life insurance contracts		23	21	44		22	20	42
Rabbi trust investments subtotal	73	36	21	130	73	38	20	131
Total assets	262	36	21	319	290	38	20	348
Liabilities								
Deferred compensation obligation		(24)		(24)		(28)		(28)
Total liabilities		(24)		(24)		(28)		(28)
Total net assets	$ 262	$ 12	$ 21	$ 295	$ 290	$ 10	$ 20	$ 320

	Pepco				DPL				ACE			
As of June 30, 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)]	$ 144	$	$	$ 144	$	$	$	$	$ 29	$	$	$ 29
Rabbi trust investments												
Cash equivalents	43			43								
Fixed income		13		13								
Life insurance contracts		23	21	44								
Rabbi trust investments subtotal	43	36	21	100								
Total assets	187	36	21	244					29			29

Liabilities												
Deferred compensation obligation		(4)		(4)		(1)		(1)				
Total liabilities		(4)		(4)		(1)		(1)				
Total net assets (liabilities)	$ 187	$ 32	$ 21	$ 240	$	$ (1)	$	$ (1)	$ 29	$	$	$ 29

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pepco				DPL				ACE			
As of December 31, 2016	**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	$ 42	$	$	$ 42	$ 130	$	$	$ 130
Mark-to-market derivative assets[(b)]					2			2				
Effect of netting and allocation of collateral					(2)			(2)				
Mark-to-market derivative assets subtotal												
Rabbi trust investments												
Cash equivalents	43			43								
Fixed income		16		16								
Life insurance contracts		22	19	41								
Rabbi trust investments subtotal	43	38	19	100								
Total assets	76	38	19	133	42			42	130			130
Liabilities												
Deferred compensation obligation		(5)		(5)		(1)		(1)				
Total liabilities		(5)		(5)		(1)		(1)				
Total net assets (liabilities)	$ 76	$ 33	$ 19	$ 128	$ 42	$ (1)	$	$ 41	$ 130	$	$	$ 130

(a) PHI excludes cash of $24 million and $19 million at June 30, 2017 and December 31, 2016 and includes long term restricted cash of $22 million and $23 million at June 30, 2017 and December 31, 2016 which is reported in other deferred debits on the balance sheet. Pepco excludes cash of $9 million at June 30, 2017 and December 31, 2016. DPL excludes cash of $6 million and $4 million at June 30, 2017 and December 31, 2016. ACE excludes cash of $7 million and $3 million at June 30, 2017 and December 31, 2016 and includes long term restricted cash of $22 million and $23 million at June 30, 2017 and December 31, 2016 which is reported in other deferred debits on the balance sheet.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2017 and 2016:

	Generation					ComEd	*Successor* PHI		Exelon
Three Months Ended June 30, 2017	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[a]**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of March 31, 2017	$ 683	$ 20	$ 565	$ 40	$ 1,308	$ (282)	$ 20	$	$ 1,046
Total realized / unrealized gains (losses)									
Included in net income	1		(3)[b]		(2)				(2)
Included in noncurrent payables to affiliates	4				4			(4)	
Included in payable for Zion Station decommissioning		1			1				1
Included in regulatory assets						26		4	30
Change in collateral			31		31				31
Purchases, sales, issuances and settlements									
Purchases	19		21	1	41				41
Sales			(13)		(13)				(13)
Settlements	(24)				(24)				(24)
Transfers into Level 3			(8)		(8)				(8)
Transfers out of Level 3			(4)		(4)				(4)
Balance at June 30, 2017	$ 683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$	$ 1,098
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2017	$	$	$ 43	$	$ 43	$	$	$	$ 43

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					ComEd	*Successor* PHI	Exelon	
Six Months Ended June 30, 2017	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[(a)]**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of December 31, 2016	$ 677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$	$ 993
Total realized / unrealized gains (losses)									
Included in net income	4		(46)[(b)]	1	(41)		1		(40)
Included in noncurrent payables to affiliates	13				13			(13)	
Included in payable for Zion Station decommissioning		1			1				1
Included in regulatory assets						2		13	15
Change in collateral			69		69				69
Purchases, sales, issuances and settlements									
Purchases	36	1	90	3	130				130
Sales			(15)		(15)				(15)
Issuances							(1)		(1)
Settlements	(47)				(47)				(47)
Transfers into Level 3			(10)		(10)				(10)
Transfers out of Level 3			8	(5)	3				3
Balance as of June 30, 2017	$ 683	$ 21	$ 589	$ 41	$ 1,334	$ (256)	$ 20	$	$ 1,098
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2017	$ 2	$	$ 102	$ 1	$ 105	$	$ 1	$	$ 106

(a) Includes $25 million of increases in fair value and an increase for realized losses due to settlements of $1 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2017. Includes $5 million of decreases in fair value and an increase for realized losses due to settlements of $7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the six months ended June 30, 2017.

(b) Includes a reduction for the reclassification of $46 million and $148 million of realized gains due to the settlement of derivative contracts for the three and six months ended June 30, 2017.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					ComEd	*Successor* PHI		Exelon
Three Months Ended June 30, 2016	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives [(a)]**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of March 31, 2016	$ 684	$ 25	$ 1,047	$ 36	$ 1,792	$ (265)	$ 20	$	$ 1,547
Total realized / unrealized gains (losses)									
Included in net income	4		(428)[(b)]		(424)		1		(423)
Included in noncurrent payables to affiliates	8				8			(8)	
Included in regulatory assets						44		8	52
Change in collateral			(32)		(32)				(32)
Purchases, sales, issuances and settlements									
Purchases	85		23	1	109				109
Sales	(1)		(1)		(2)				(2)
Issuances							(1)		(1)
Settlements	(65)				(65)				(65)
Transfers into Level 3									
Transfers out of Level 3									
Balance as of June 30, 2016	$ 715	$ 25	$ 609	$ 37	$ 1,386	$ (221)	$ 20	$	$ 1,185
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2016	$ 3	$	$ (264)	$	$ (261)	$	$ 1	$	$ (260)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2016	Generation NDT Fund Investments	Generation Pledged Assets for Zion Station Decommissioning	Generation Mark-to-Market Derivatives	Generation Other Investments	Total Generation	ComEd Mark-to-Market Derivatives[a]	*Successor* PHI[c] Life Insurance Contracts	Eliminated in Consolidation	Exelon Total
Balance as of December 31, 2015	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$	$	$ 1,529
Included due to merger							20		20
Total realized / unrealized gains (losses)									
Included in net income	6		(434)[b]		(428)		1		(427)
Included in noncurrent payables to affiliates	12				12			(12)	
Included in payable for Zion Station decommissioning		2			2				2
Included in regulatory assets						26		12	38
Change in collateral			(82)		(82)				(82)
Purchases, sales, issuances and settlements									
Purchases	119	1	82	4	206				206
Sales	(1)		(3)		(4)				(4)
Issuances							(1)		(1)
Settlements	(91)				(91)				(91)
Transfers into Level 3			2		2				2
Transfers out of Level 3			(7)		(7)				(7)
Balance as of June 30, 2016	$ 715	$ 25	$ 609	$ 37	$ 1,386	$ (221)	$ 20	$	$ 1,185
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of June 30, 2016	$ 4	$	$ (45)	$	$ (41)	$	$ 1	$	$ (40)

(a) Includes $40 million of increases in fair value and an increase for realized losses due to settlements of $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2016. Includes $15 million of increases in fair value and an increase for realized losses due to settlements of $11 million for the six months ended June 30, 2016.

(b) Includes a reduction for the reclassification of $164 million and $389 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three and six months ended June 30, 2016.

(c) Successor period represents activity from March 24, 2016 through June 30, 2016. See tables below for PHI s predecessor periods, as well as activity for Pepco for the three and six months ended June 30, 2017 and 2016.

PHI	*Predecessor* January 1, 2016 to March 23, 2016 Preferred Stock	Life Insurance Contracts
Beginning Balance	$ 18	$ 19
Total realized / unrealized gains (losses)		
Included in net income	(18)	1

Ending Balance	$	$ 20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$	$ 1

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Life Insurance Contracts			
	Three Months Ended June 30,		Six Months Ended June 30,	
Pepco	**2017**	**2016**	**2017**	**2016**
Beginning balance	$ 20	$ 20	$ 20	$ 19
Total realized / unrealized gains (losses)				
Included in net income		1	1	2
Purchases, sales, issuances and settlements				
Issuances		(1)	(1)	(1)
Ending balance	$ 20	$ 20	$ 20	$ 20
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$	$ 1	$	$ 2

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2017 and 2016:

	Generation			*Successor* 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 June 30, 2017	$ (51)	$ 48	$ 1	$	$ (51)	$ 48	$ 1
Total gains (losses) included in net income for the six months ended June 30, 2017	37	(83)	5	1	37	(83)	6
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2017		43				43	
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2017	140	(38)	3	1	140	(38)	4

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation			*Successor* 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 June 30, 2016	$ (462)	$ 34	$ 4	$ 1	$ (462)	$ 34	$ 5
Total gains (losses) included in net income for the six months ended June 30, 2016	(413)	(21)	6	1	(413)	(21)	7
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2016	(274)	10	3	1	(274)	10	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2016	(20)	(25)	4	1	(20)	(25)	5

	Predecessor PHI January 1, 2016 to March 23, 2016	Pepco Three Months Ended June 30,		Six Months Ended June 30,	
		2017	2016	2017	2016
	Other, net[(a)]	Other, net[(a)]			
Total gains (losses) included in net income	$ (17)	$	$ 1	$ 1	$ 2
Change in the unrealized gains (losses) relating to assets and liabilities held	1		1	1	2

(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 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.

Preferred Stock Derivative (PHI). In connection with entering into the PHI Merger Agreement, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of Preferred stock. The Preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

shares of the Preferred stock in the event of such a termination were separately accounted for as derivatives. These Preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management s assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI Preferred stock derivative was reduced to zero as of March 23, 2016. The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

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 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 June 30, 2017, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately $280 million, $218 million, and $98 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 June 30, 2017. 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 June 30, 2017, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation s NDT assets.

See Note 12 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2. The life insurance policies are valued using the cash surrender value of the policies, net of loans against those policies, which is provided by a third-party. Certain life insurance policies, which consist primarily of mutual funds that are priced based on observable market data, have been categorized as Level 2 because the life insurance policies can be liquidated at the reporting date for the value of the underlying assets. Life insurance policies that are valued using unobservable inputs have been categorized as Level 3.

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

Exelon may utilize fixed-to-floating interest rate swaps, 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 9 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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)

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

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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 $2.86 and $0.41 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 9 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 June 30, 2017	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Exelon and Generation)[a][c]	$ 453	Discounted Cash Flow	Forward power price	$8 $124
			Forward gas price	$1.92 $9.37
		Option Model	Volatility percentage	11% 253%
Mark-to-market derivatives Proprietary trading (Exelon and Generation)[a][c]	$ 6	Discounted Cash Flow	Forward power price	$11 $73
Mark-to-market derivatives (Exelon and ComEd)	$ (256)	Discounted Cash Flow	Forward heat rate[b]	9x 10x
			Marketability reserve	3% 8%
			Renewable factor	89% 121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) 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.
(c) The fair values do not include cash collateral posted on level three positions of $130 million as of June 30, 2017.

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Type of trade	Fair Value at December 31, 2016	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives Economic Hedges (Exelon and Generation)[a][c]	$ 435	Discounted Cash Flow	Forward power price	$11	$130
			Forward gas price	$1.72	$9.2
		Option Model	Volatility percentage	8%	173%
Mark-to-market derivatives Proprietary trading (Exelon and Generation)[a][c]	$ (3)	Discounted Cash Flow	Forward power price	$19	$79
Mark-to-market derivatives (Exelon and ComEd)	$ (258)	Discounted Cash Flow	Forward heat rate[b]	8x	9x
			Marketability reserve	3%	8%
			Renewable factor	89%	121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) 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.
(c) The fair values do not include cash collateral posted on level three positions of $61 million as of December 31, 2016.

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.

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.

9. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate 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 energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting 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 each period. 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 hedge, and fair value hedge. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Generation has also entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives, and retail load aggregators, as well as contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. These non-derivative contracts are accounted for primarily under the accrual method of accounting. 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.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities 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. 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 energy

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

purchases, natural gas transportation and pipeline capacity agreements, and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management s policies and hedging objectives, the market, weather conditions, operational and other factors. 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.

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 June 30, 2017, the percentage of expected generation hedged for the major reportable segments is 96%-99%, 71%-74%, and 39%-42% for 2017, 2018, and 2019, 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 ComEd, PECO, and BGE to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. 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 2016 Form 10-K for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO s price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts. PECO has certain full requirements contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

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 in order 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

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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 financial position or results of operations 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. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE s 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. All of 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 price risk related to electric supply procurement is limited. Pepco locks in fixed prices for all of 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 all of its SOS requirements through full requirements contracts. DPL s 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 versus the forecast 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 fifty percent (50%) of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The fifty percent (50%) hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its gas hedging program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL s derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL s physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE s wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE s 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. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading activities, which included settled physical sales volumes of 2,312 GWhs and 4,162 GWhs for the three and six months ended June 30, 2017, respectively, and 1,289 GWhs and 2,509 GWhs and for the three and six months June 30, 2016, respectively, are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s revenue from energy marketing activities. ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes.

Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO, BGE and PHI)

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, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At June 30, 2017, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had $492 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the interest rate hedges are 100% effective, a

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hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately $3 million decrease in Exelon Consolidated pre-tax income for the six months ended June 30, 2017. 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. Below is a summary of the interest rate and foreign exchange hedge balances as of June 30, 2017:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$	$ 14	$ 3	$ (11)	$ 6	$	$ 6
Mark-to-market derivative assets (noncurrent assets)		3	1	(2)	2	11	13
Total mark-to-market derivative assets		17	4	(13)	8	11	19
Mark-to-market derivative liabilities (current liabilities)		(17)	(4)	11	(10)		(10)
Mark-to-market derivative liabilities (noncurrent liabilities)		(3)		2	(1)		(1)
Total mark-to-market derivative liabilities		(20)	(4)	13	(11)		(11)
Total mark-to-market derivative net assets (liabilities)	$	$ (3)	$	$	$ (3)	$ 11	$ 8

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting 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. These are not reflected in the table above.

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

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2016:

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[a]	Collateral and Netting[b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$	$ 17	$ 4	$ (13)	$ 8	$	$ 8
Mark-to-market derivative assets (noncurrent assets)		11	1	(8)	4	16	20
Total mark-to-market derivative assets		28	5	(21)	12	16	28
Mark-to-market derivative liabilities (current liabilities)	(7)	(13)	(2)	14	(8)		(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(3)	(8)	(2)	9	(4)		(4)
Total mark-to-market derivative liabilities	(10)	(21)	(4)	23	(12)		(12)
Total mark-to-market derivative net assets (liabilities)	$ (10)	$ 7	$ 1	$ 2	$	$ 16	$ 16

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting 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. These are not reflected in the table above.

Fair Value Hedges. For derivative instruments that are designated and qualify 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 current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

Income Statement Location	Three Months Ended June 30,			
	2017	2016	2017	2016
	Gain (loss) on Swaps		Gain (loss) on Borrowings	

Exelon	Interest expense	$ 1	$ 5	$ 2	$ (1)

Income Statement Location		Six Months Ended June 30,			
		2017	2016	2017	2016
		Gain (loss) on Swaps		Gain (loss) on Borrowings	
Exelon	Interest expense	$ (4)	$ 22	$ 10	$ (16)

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At June 30, 2017, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $11 million. At December 31, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $16 million. During the three and six months ended June 30, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $3 million gain, a $7 million gain, a $4 million gain, and a $6 million gain, respectively.

Cash Flow Hedges. During the first and second quarter of 2016, Exelon entered into $600 million and $100 million of floating-to-fixed forward starting interest rate swaps, respectively, to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swaps were designated as cash flow hedges. Exelon terminated the swaps during the second quarter of 2016 upon issuance of the debt. Exelon recognized a loss of $3 million related to the swaps and $3 million of AOCI will be amortized into Other, net in Exelon s Consolidated Statement of Operations and Comprehensive Income over the term of the debt. See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

During the first quarter of 2016, Exelon entered into a $100 million floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swap was designated as a cash flow hedge. Exelon terminated the swap during the first quarter of 2016 upon issuance of the debt. Exelon did not recognize a gain or loss as a result of the termination of the swap and an immaterial amount of AOCI will be amortized into Other, net in Exelon s Consolidated Statement of Operations and Comprehensive Income over the term of the debt.

During the first quarter of 2014, EGR, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with its long-term borrowings. The swaps were de-designated as cash flow hedges and, during the second quarter of 2017, upon termination of the debt, Generation terminated the swaps. The total notional amount of the swaps was $164 million. No gain or loss was recognized as a result of the termination of the swaps. See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

During the three and six months ended June 30, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships was immaterial.

Economic Hedges. During the third quarter of 2014, EGTP, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $492 million as of June 30, 2017 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. During the first quarter of 2017, the swap was de-designated. At June 30, 2017, the subsidiary had a $8 million derivative liability related to the swap.

During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swaps. The total notional amount of the swaps was $25 million. No gain or loss was recognized as a result of the termination of the swaps.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2016 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the termination of debt, Generation terminated the swap. The total notional amount of the swap was $24 million. No gain or loss was recognized as a result of the termination of the swap.

At June 30, 2017, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $103 million in notional amounts of 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.

Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO, BGE, PHI and DPL)

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the 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 June 30, 2017 and December 31, 2016, $2 million and $8 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 as of the balance sheet date there were no positions to offset. 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 a non affiliate 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, 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 June 30, 2017:

	Generation				ComEd	DPL			*Successor* PHI	Exelon
Derivatives	**Economic Hedges**	**Proprietary Trading**	**Collateral and Netting**[(a) (e)]	**Subtotal**[(b)]	**Economic Hedges**[(c)]	**Economic Hedges**[(d)]	**Collateral and Netting**[(a)]	**Subtotal**	**Subtotal**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 3,198	$ 58	$ (2,429)	$ 827	$	$	$	$	$	$ 827
Mark-to-market derivative assets (noncurrent assets)	1,736	23	(1,308)	451						451
Total mark-to-market derivative assets	4,934	81	(3,737)	1,278						1,278
Mark-to-market derivative liabilities (current liabilities)	(2,895)	(52)	2,732	(215)	(19)					(234)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,644)	(25)	1,490	(179)	(237)					(416)
Total mark-to-market derivative liabilities	(4,539)	(77)	4,222	(394)	(256)					(650)
Total mark-to-market derivative net assets (liabilities)	$ 395	$ 4	$ 485	$ 884	$ (256)	$	$	$	$	$ 628

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting 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 $149 million and $74 million, respectively, and current and noncurrent liabilities are shown net of collateral of $155 million and $107 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $485 million at June 30, 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), $84 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, 2016:

Description	Generation				ComEd	DPL			*Successor* PHI	Exelon
	Economic Hedges	Proprietary Trading	Collateral and Netting[(a) (e)]	Subtotal[(b)]	Economic Hedges[(c)]	Economic Hedges[(d)]	Collateral and Netting[(a)]	Subtotal	Subtotal	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,623	$ 55	$ (2,769)	$ 909	$	$ 2	$ (2)	$	$	$ 909
Mark-to-market derivative assets (noncurrent assets)	1,467	21	(1,016)	472						472
Total mark-to-market derivative assets	5,090	76	(3,785)	1,381		2	(2)			1,381
Mark-to-market derivative liabilities (current liabilities)	(3,165)	(54)	2,964	(255)	(19)					(274)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,274)	(25)	1,150	(149)	(239)					(388)
Total mark-to-market derivative liabilities	(4,439)	(79)	4,114	(404)	(258)					(662)
Total mark-to-market derivative net assets (liabilities)	$ 651	$ (3)	$ 329	$ 977	$ (258)	$ 2	$ (2)	$	$	$ 719

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting 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 $100 million and $72 million, respectively, and current and noncurrent liabilities are shown net of collateral of $95 million and $62 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $329 million at December 31, 2016.

(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), $(158) million represents variation margin on the exchanges.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Cash Flow Hedges (Exelon and Generation). The tables below provide the activity of OCI related to cash flow hedges for the six months ended June 30, 2017 and 2016, containing information about the changes in the fair value of cash flow hedges and the reclassification from Accumulated OCI 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	
		Generation	Exelon
Three Months Ended June 30, 2017	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative loss at March 31, 2017		$ (13)	$ (11)
Effective portion of changes in fair value		(1)	(1)
Accumulated OCI derivative loss at June 30, 2017		$ (14)	$ (12)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Six Months Ended June 30, 2017	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative loss at December 31, 2016		$ (19)	$ (17)
Effective portion of changes in fair value		1	1
Reclassifications from AOCI to net income	Interest Expense	4[(a)]	4[(a)]
Accumulated OCI derivative loss at June 30, 2017		$ (14)	$ (12)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended June 30, 2016	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative loss at March 31, 2016		$ (26)	$ (26)
Reclassifications from AOCI to net income	Interest Expense	1	
Accumulated OCI derivative loss at June 30, 2016		$ (25)	$ (26)

	Income Statement	Total Cash Flow Hedge OCI Activity, Net of Income Tax

Six Months Ended June 30, 2016	Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative loss at December 31, 2015		$ (21)	$ (19)
Effective portion of changes in fair value		(7)	(10)
Reclassifications from AOCI to net income	Interest Expense	3(b)	3(b)
Accumulated OCI derivative loss at June 30, 2016		$ (25)	$ (26)

(a) Amount is net of related income tax expense of $3 million for the six months ended June 30, 2017.
(b) Amount is net of related income tax expense of $2 million for the six months ended June 30, 2016.

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Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps (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. For the three and six months ended June 30, 2017 and 2016, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in Operating revenues or Purchased power and fuel expense, or Interest expense at Exelon and Generation 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. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized generally represents the recognized change in fair value that was reclassified from unrealized to realized when the transaction to which the derivative relates occurs.

	Generation			Exelon
Three Months Ended June 30, 2017	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ (100)	$ (62)	$ (162)	$ (162)
Reclassification to realized at settlement of commodity positions	(41)	21	(20)	(20)
Net commodity mark-to-market gains (losses)	(141)	(41)	(182)	(182)
Change in fair value of treasury positions	(2)		(2)	(2)
Reclassification to realized at settlement of treasury positions				
Net treasury mark-to-market gains (losses)	(2)		(2)	(2)
Net mark-to-market gains (losses)	$ (143)	$ (41)	$ (184)	$ (184)

	Generation			Exelon
Six Months Ended June 30, 2017	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ (9)	$ (197)	$ (206)	$ (206)
Reclassification to realized of commodity positions	(87)	63	(24)	(24)
Net commodity mark-to-market gains (losses)	(96)	(134)	(230)	(230)
Change in fair value of treasury positions	(1)		(1)	(1)
Reclassification to realized of treasury positions	(2)		(2)	(2)
Net treasury mark-to-market gains (losses)	(3)		(3)	(3)
Net mark-to-market gains (losses)	$ (99)	$ (134)	$ (233)	$ (233)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation			Exelon
Three Months Ended June 30, 2016	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ (432)	$ 235	$ (197)	$ (197)
Reclassification to realized at settlement of commodity positions	(181)	76	(105)	(105)
Net commodity mark-to-market gains (losses)	(613)	311	(302)	(302)
Change in fair value of treasury positions	1		1	1
Reclassification to realized at settlement of treasury positions	(3)		(3)	(3)
Net treasury mark-to-market gains (losses)	(2)		(2)	(2)
Net mark-to-market gains (losses)	$ (615)	$ 311	$ (304)	$ (304)

	Generation			Exelon
Six Months Ended June 30, 2016	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ (153)	$ 109	$ (44)	$ (44)
Reclassification to realized of commodity positions	(392)	243	(149)	(149)
Net commodity mark-to-market gains (losses)	(545)	352	(193)	(193)
Change in fair value of treasury positions	(4)		(4)	(4)
Reclassification to realized of treasury positions	(4)		(4)	(4)
Net treasury mark-to-market gains (losses)	(8)		(8)	(8)
Net mark-to-market gains (losses)	$ (553)	$ 352	$ (201)	$ (201)

Proprietary Trading Activities (Exelon and Generation). For the three and six months ended June 30, 2017 and 2016, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) before income taxes relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate and foreign exchange derivative contracts 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. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Three Months Ended June 30,	Six Months Ended June 30,

	2017	2016	2017	2016
Change in fair value of commodity positions	$ 6	$ 5	$ 6	$ 14
Reclassification to realized of commodity positions	(6)	(5)	(7)	(11)
Net commodity mark-to-market gains (losses)			(1)	3
Change in fair value of treasury positions			(1)	(2)
Reclassification to realized of treasury positions		(1)		1
Net treasury mark-to-market gains (losses)		(1)	(1)	(1)
Total net mark-to-market gains (losses)	$	$ (1)	$ (2)	$ 2

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Credit Risk (All Registrants)

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

The following tables provide information on Generation s credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of June 30, 2017. 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 $23 million, $27 million, $21 million, $41 million, $12 million, and $6 million as of June 30, 2017, respectively.

Rating as of June 30, 2017	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	$ 878	$ 14	$ 864	1	$ 299
Non-investment grade	47	1	46		
No external ratings					
Internally rated investment grade	327		327		
Internally rated non-investment grade	123	14	109		
Total	$ 1,375	$ 29	$ 1,346	1	$ 299

Net Credit Exposure by Type of Counterparty	As of June 30, 2017
Financial institutions	$ 89
Investor-owned utilities, marketers, power producers	563
Energy cooperatives and municipalities	560
Other	134
Total	$ 1,346

(a) As of June 30, 2017, credit collateral held from counterparties where Generation had credit exposure included $19 million of cash and $10 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 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, 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 June 30, 2017, ComEd s net credit exposure to suppliers was approximately $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 2016 Form 10-K for additional information.

PECO s supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements 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 PECO s net credit exposure. As of June 30, 2017, PECO had no material net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for additional information.

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 June 30, 2017, 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 2016 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. 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, subject to an unsecured credit cap. 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 BGE s net credit exposure. The seller s credit exposure is calculated each business day. As of June 30, 2017, BGE had no net credit exposure to suppliers.

BGE s regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE s recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At June 30, 2017, BGE had credit exposure of less than $1 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 June 30, 2017, 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 2016 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 June 30, 2017, DPL had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

Collateral and Contingent-Related Features (All Registrants)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, 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 (i.e., NYMEX, ICE). 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	June 30, 2017	December 31, 2016
Gross Fair Value of Derivative Contracts Containing this Feature[a]	$ (942)	$ (960)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[b]	601	627
Net Fair Value of Derivative Contracts Containing This Feature[c]	$ (341)	$ (333)

(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 $517 million and letters of credit posted of $278 million and cash collateral held of $34 million and letters of credit held of $21 million as of June 30, 2017 for external counterparties with derivative positions. Generation had cash collateral posted of $347 million and letters of credit posted of $284 million and cash collateral held of $24 million and letters of credit held of $28 million at December 31, 2016 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody s), Generation would have been required to post additional collateral of $1.8 billion and $1.9 billion as of June 30, 2017 and December 31, 2016, 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 June 30, 2017, Generation s swaps were in a liability position with a fair value of $3 million and Exelon s swaps were in an asset position, with a fair value of $8 million.

See Note 26 Segment Information of the Exelon 2016 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 June 30, 2017, ComEd held approximately $13 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd s annual renewable energy contracts, collateral postings are required to cover a fixed value

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for RECs only. In addition, 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 June 30, 2017, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. If ComEd lost its investment grade credit rating as of June 30, 2017, it would have been required to post approximately $12 million of collateral to its counterparties. See Note 3 Regulatory Matters of the Exelon 2016 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 June 30, 2017, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2017, PECO could have been required to post approximately $21 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 full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE 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 June 30, 2017, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2017, BGE could have been required to post approximately $36 million of collateral to its counterparties.

Pepco s full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require Pepco to post collateral.

DPL s full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require DPL to post collateral.

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 June 30, 2017, DPL could have been required to post an additional amount of approximately $10 million of collateral to its natural gas counterparties.

ACE s full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require ACE to post collateral.

10. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

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

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

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 meets its short-term liquidity requirement primarily through the issuance of short-term notes and the Exelon intercompany money pool.

Commercial Paper

The Registrants had the following amounts of commercial paper borrowings outstanding as of June 30, 2017 and December 31, 2016:

Commercial Paper Borrowings	**June 30, 2017**	**December 31, 2016**
Exelon Corporate	$	$
Generation	569	620
ComEd	389	
BGE	85	45
Pepco		23
DPL	25	
ACE	42	

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 expires on March 22, 2018. 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

On January 9, 2017, the credit agreement for Generation s $75 million bilateral credit facility was amended and restated to increase the facility size to $100 million and extend the maturity to January 2019. This facility will solely be used by Generation to issue letters of credit.

On May 26, 2016, Exelon Corporate, Generation, ComEd, PECO and BGE entered into amendments to each of their respective syndicated revolving credit facilities, which extended the maturity of each of the facilities to May 26, 2021. Exelon Corporate also increased the size of its facility from $500 million to $600 million. On May 26, 2016, PHI, Pepco, DPL and ACE entered into an amendment to their Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from $1.5 billion to $900 million and (iv) converted its financial covenant from a debt to capitalization leverage ratio to an interest coverage ratio. On May 26, 2017, each of the Registrants respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2022.

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Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 30, 2017, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes (a)	3.50%	June 1, 2022	$ 1,150	Refinance Exelon s Junior Subordinated Notes issued in June 2014.
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 13	Albany Green Energy biomass generation development.
Generation	Energy Efficiency Project Financing	3.90%	February 1, 2018	$ 12	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing	2.61%	September 30, 2018	$ 6	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing	3.53%	April 1, 2019	$ 8	Funding to install energy conservation measures for the State Department project.
Generation	Energy Efficiency Project Financing	3.72%	May 1, 2018	$ 3	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Senior Notes	2.95%	January 15, 2020	$ 250	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	Senior Notes	3.40%	March 15, 2022	$ 500	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 6	Funding for general corporate purposes.
Pepco	Energy Efficiency Project Financing	3.30%	December 15, 2017	$ 1	Funding to install energy conservation measures for the DOE Germantown project.
Pepco	First Mortgage Bonds	4.15%	March 15, 2043	$ 200	Funding to repay outstanding commercial paper and for general corporate purposes.

(a) See the Junior Subordinated Notes discussion below for further information.

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EGTP Nonrecourse Debt

In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 18, 2021. The term loan bears interest at a variable rate equal to LIBOR plus 4.75%, subject to a 1% LIBOR floor with interest payable quarterly. As of June 30, 2017, $662 million was outstanding. As part of the agreement, a revolving credit facility was established for the amount of $20 million available through, and scheduled to mature on September 18, 2019. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants. See Note 9 Derivative Financial Instruments for additional information regarding interest rate swaps.

On May 2, 2017, EGTP entered into a consent agreement with its lenders, which resulted in the outstanding debt balance being classified as Long-term debt due within one year on Exelon s and Generation s Consolidated Balance Sheets. See Note 4 Mergers, Acquisitions and Dispositions and Note 6 Impairment of Long-Lived Assets for more information.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon s $1.15 billion of 2.50% junior subordinated notes due in 2024 (2024 notes) and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 (Remarketing). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of June 30, 2017. See Note 16 Earnings Per Share and Equity for further information on the issuance of common stock.

BGE Redemption of Trust Preferred Securities

On August 1, 2017, BGE announced that it intends to redeem all of the outstanding shares of BGE Capital Trust II 6.20% Preferred Securities, which totaled $258 million at June 30, 2017. The securities will be redeemed on August 28, 2017, pursuant to the optional redemption provisions of the Indenture under which the securities were issued. The redemption will be made to stockholders of record as of the close of business on August 25, 2017. The redemption price per share is $25.19, which equals the stated value per share plus accrued and unpaid dividends to, but excluding, the redemption date. No dividends on the Securities being redeemed will accrue on or after the redemption date, nor will any interest accrue on amounts held to pay the redemption price.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

11. Income Taxes (All Registrants)

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

	Three Months Ended June 30, 2017								
									Successor
	Exelon[(a)]	Generation[(b)]	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	(2,745.7)	5.6	5.8	(0.6)	5.0	3.2	4.6	5.6	4.3
Qualified nuclear decommissioning trust fund income	3,156.6	(6.3)							
Amortization of investment tax credit, including deferred taxes on basis difference	(528.7)	0.9	(0.2)	(0.1)	(0.2)	(0.1)	(0.1)	(0.4)	(0.1)
Plant basis differences	(2,764.4)		(0.2)	(16.0)	(0.3)	(6.2)	(1.7)	(3.3)	(4.8)
Production tax credits and other credits	(1,035.7)	2.0							
Noncontrolling interests	84.7	(0.2)							
Like-kind exchange[(c)]	(5,362.4)		5.9						
Other	1,960.6	1.1	0.5	0.2	1.3	(0.2)	0.9	(3.6)	0.9
Effective income tax rate	(7,200.0)%	38.1%	46.8%	18.5%	40.8%	31.7%	38.7%	33.3%	35.3%

	Three Months Ended June 30, 2016								
									Successor
	Exelon	Generation[(d)]	ComEd	PECO	BGE[(e)]	Pepco	DPL	ACE	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	2.3	(116.7)	4.8	0.3	2.0	3.5	4.8	5.9	6.1
Qualified nuclear decommissioning trust fund income	5.7	591.2							
Amortization of investment tax credit, including deferred taxes on basis difference	(1.8)	(157.8)	(0.2)	(0.1)	(0.4)	(0.1)	(0.6)	(1.6)	(0.3)
Plant basis differences[(f)]	(6.9)		(0.4)	(11.3)	(20.6)	(5.7)	(3.5)	(7.1)	(7.0)
Production tax credits and other credits	(5.8)	(603.0)							
Noncontrolling interest	0.9	94.4							
Statute of limitations expiration	(1.7)	(410.8)							
Merger expenses	0.2					0.2	3.1		1.0
Other[(g)]	(3.3)	(52.3)	(0.6)	(5.2)	(1.0)	(1.0)	1.2	7.8	1.0
Effective income tax rate	24.6%	(620.0)%	38.6%	18.7%	15.0%	31.9%	40.0%	40.0%	35.8%

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Six Months Ended June 30, 2017								
									Successor
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**PHI**
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	(1.0)	(13.6)	5.3	(0.1)	5.1	3.8	5.1	5.6	4.6
Qualified nuclear decommissioning trust fund income	5.6	51.2							
Amortization of investment tax credit, including deferred taxes on basis difference	(0.7)	(5.4)	(0.2)	(0.1)	(0.1)	(0.1)	(0.2)	(0.4)	(0.2)
Plant basis differences	(4.3)		(0.2)	(14.3)	(0.7)	(6.0)	(1.8)	(3.3)	(4.3)
Production tax credits and other credits	(1.4)	(12.3)							
Noncontrolling interests	(0.1)	(0.5)							
Merger expenses[h]	(11.4)	(13.7)				(16.2)	(15.1)	(85.3)	(23.8)
Fitzpatrick bargain purchase gain	(6.5)	(60.0)							
Like-kind exchange[c]	(3.7)		2.9						
Other	0.3	(4.2)	0.4	(0.1)	0.3	(0.7)	1.0	(1.6)	
Effective income tax rate	11.8%	(23.5)%	43.2%	20.4%	39.6%	15.8%	24.0%	(50.0)%	11.3%

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Six Months Ended June 30, 2016								*Successor* March 24, 2016 to June 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco(i)	DPL(i)	ACE(i)	PHI(i)	PHI
U.S. Federal statutory rate	35.0%	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(i)	0.8	2.6	4.9	0.7	4.6	(9.5)	(5.2)	5.9	5.2	11.9
Qualified nuclear decommissioning trust fund income	5.6	9.8								
Amortization of investment tax credit, including deferred taxes on basis difference	(1.7)	(2.5)	(0.2)	(0.1)	(0.1)	0.1	0.4	0.1	0.1	(0.9)
Plant basis differences(f)	(6.3)		(0.3)	(10.2)	(4.5)	12.6	2.0	1.0	1.7	(13.5)
Production tax credits and other credits	(5.5)	(9.6)								
Noncontrolling interest	0.7	1.2								
Statute of limitations expiration	(1.0)	(3.9)								
Merger expenses	14.5					(36.1)	(30.5)	(17.7)	(18.9)	11.1
Other(g)	(2.8)	(3.8)	(0.1)	(2.4)	0.1	(0.5)	(0.1)	(0.1)		3.6
Effective income tax rate	39.3%	28.8%	39.3%	23.0%	35.1%	1.6%	1.6%	24.2%	23.1%	47.2%

(a) The effective tax rate for the three months ended June 30, 2017 is disproportionately impacted due to the decline in consolidated pre-tax GAAP earnings as compared to the federal and state tax impacts of the Like-kind exchange, tax credits, Plant basis differences, and Qualified nuclear decommissioning trust fund income.
(b) Generation recognized a loss before income taxes for the three months ended June 30, 2017. As a result, positive percentages represent an income tax benefit for the period presented.
(c) See Like-Kind Exchange within the Other Income Tax Matters section below for further details.
(d) The effective tax rate for the three months ended June 30, 2016, is disproportionately impacted due to the decline in pre-tax GAAP earnings as compared to the changes in tax credits and other reconciling items. In three months ended June 30, 2016, due to the expiration of a statute of limitations, Generation recorded an income tax benefit of $16 million. The statute of limitations expired in the third quarter of 2015; therefore, this represents an out of period adjustment.
(e) The effective tax rate for the three months ended June 30, 2016 is disproportionately impacted due to the decline in pre-tax GAAP earnings and changes in other reconciling items.
(f) At BGE, includes a cumulative adjustment related to a regulatory asset.
(g) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.
(h) Includes a remeasurement of uncertain federal and state income tax positions, see below.
(i) Pepco, DPL and ACE recognized a loss before income taxes for the six months ended June 30, 2016, and PHI recognized a loss before income taxes for the period of March 24, 2016, through June 30, 2016. As a result, positive percentages represent an income tax benefit for the periods presented.
(j) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Accounting for Uncertainty in Income Taxes

The Registrants have the following unrecognized tax benefits as of June 30, 2017 and December 31, 2016:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
June 30, 2017	$ 730	$ 467	$ 2	$	$ 120	$ 112	$ 59	$ 21	$

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
December 31, 2016	$ 916	$ 490	$ (12)	$	$ 120	$ 172	$ 80	$ 37	$ 22

Exelon established a liability for an uncertain tax position associated with the tax deductibility of certain merger commitments incurred by Exelon in connection with the acquisitions of Constellation in 2012 and PHI in 2016. In the first quarter 2017, as a part of its examination of Exelon s return, the IRS National Office issued guidance concurring with Exelon s position that the merger commitments were deductible. As a result, Exelon, Generation, PHI, Pepco, DPL, and ACE decreased their liability for unrecognized tax benefits by $146 million, $19 million, $59 million, $21 million, $16 million, and $22 million, respectively, as of June 30, 2017, resulting in a benefit to Income taxes on Exelon s, Generation s, PHI s, Pepco s, DPL s and ACE s Consolidated Statements of Operations and Comprehensive Income and corresponding decreases in their effective tax rates.

Exelon reduced the liability related to the uncertain tax position associated with the like-kind exchange in the second quarter of 2017. Please see the Other Income Tax Matters section below for additional details related to the like-kind exchange adjustments made in the second quarter of 2017.

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 June 30, 2017, Exelon and ComEd have approximately $39 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.

Settlement of Income Tax Audits

As of June 30, 2017, Exelon, Generation, BGE, PHI, Pepco, and DPL have approximately $257 million, $57 million, $120 million, $80 million, $59 million, and $21 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 and potential settlements. Of the above unrecognized tax benefits, Exelon and Generation have $50 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, DPL, and a portion of Pepco, 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

The IRS disagreed with this position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. Exelon was unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a listed transaction that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities did not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS also asserted a penalty of approximately $90 million for a substantial understatement of tax.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court (Tax Court) and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue.

On September 19, 2016, the Tax Court rejected Exelon s position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon s evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on the asserted penalty. Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit in the second half of 2017. In June of 2017, the IRS finalized its computation of tax, penalties and interest owed by Exelon pursuant to the Tax Court s decision.

In the first quarter of 2013, Exelon concluded that it was no longer more likely than not that the like-kind exchange position would be sustained and recorded charges to earnings representing the amount of interest expense (after-tax) and incremental state income tax expense that would be payable in the event Exelon is unsuccessful in litigation. Exelon agreed to hold ComEd harmless from any unfavorable impacts on ComEd s equity of the after-tax interest and penalty amounts.

Prior to the Tax Court s decision, however, Exelon did not believe it was likely a penalty would be assessed based on applicable case law and the facts of the transaction. As a result, no charge had been recorded for the penalty or for after-tax interest on the penalty. While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to accounting standards, it is no longer more likely than not to avoid ultimate imposition of the penalty. As a result, in the third quarter of 2016, Exelon and ComEd recorded a charge to earnings of approximately $106 million and $86 million, respectively, of penalty and approximately $94 million and $64 million, respectively, of after-tax interest. Exelon and ComEd recorded the penalty and pre-tax interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon s agreement to continue to hold ComEd harmless from any unfavorable impact on its equity from the like-kind exchange position, ComEd recorded on its Consolidated Balance Sheets as of September 30, 2016, a $150 million receivable and non-cash equity contributions from Exelon.

As a result of the IRS s finalization of its computation in the second quarter 2017, Exelon recorded a benefit to earnings of approximately $26 million, consisting of an income tax benefit of $50 million and a reduction of penalties of $2 million, partially offset by after-tax interest expense of $26 million, while ComEd recorded a charge to earnings of approximately $23 million, consisting of income tax expense of $15 million and after-tax interest expense of $8 million.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In the second quarter of 2017, Exelon amended its agreement with ComEd to also hold ComEd harmless for the unfavorable impacts on its equity from the additional income tax amounts owed by ComEd as a result of the IRS s finalization of its computation related to the like-kind exchange position. Accordingly, in the second quarter of 2017, ComEd recorded an additional receivable and non-cash equity contribution from Exelon for the total $23 million.

In order to appeal the decision, Exelon is required to pay the tax, penalties and interest at the time Exelon files its appeal (expected in the second half of 2017). Exelon expects that a payment of approximately $1.3 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the second half of 2017. While Exelon will receive a tax benefit of approximately $350 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is approximately $950 million, of which approximately $300 million is attributable to ComEd after giving consideration to Exelon s agreement to hold ComEd harmless from any unfavorable impacts on ComEd s equity from the like-kind exchange position. Upon a final appellate decision, which could take up to several years, Exelon expects to receive approximately $60 million related to final interest computations.

Of the above amounts payable, Exelon deposited with the IRS $1.25 billion in October of 2016. The remaining amount will be paid in the second half of 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings. The deposit is reflected as a current asset and the related liabilities for the tax, penalty, and interest are included on Exelon s balance sheet as current obligations.

As of June 30, 2017, ComEd has a total receivable from Exelon pursuant to the hold harmless agreement of $369 million, which is included in Current Receivables from Affiliates on ComEd s Consolidated Balance Sheet. Under the agreement, Exelon will settle this receivable with ComEd no later than the time that the payments related to the like-kind exchange are due to the IRS, currently anticipated in the second half of 2017. No recovery will be sought from ComEd customers for any interest, penalty or additional income tax payment amounts resulting from the like-kind exchange tax position.

As previously disclosed, in the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. In the first quarter of 2016, Exelon terminated its interests in the remaining two municipal-owned electric generation properties in exchange for $360 million.

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

Exelon, Generation and PHI periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon, Generation and PHI to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes. Exelon and PHI s long-term marginal state income tax rate was revised in the first quarter of 2017 as a result of a statutory rate change pursuant to Exelon s marginal state income tax rate policy, resulting in the recording of a deferred state tax benefit for Exelon of $21 million, net of tax.

On July 6, 2017, Illinois enacted Senate Bill 9, which permanently increased Illinois total corporate income tax rate from 7.75% to 9.50% effective July 1, 2017. As a result of the rate change, in the third quarter of 2017, after taking into account regulatory recovery of tax increases at Exelon, Generation and ComEd

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

expect to record an estimated one-time increase to deferred income taxes of approximately $180 million, $15 million and $250 million, respectively. At ComEd, the increase to the Illinois deferred income tax liability will be offset by a regulatory asset. Exelon expects to record a decrease to income tax expense of approximately $70 million (net of federal taxes) and Generation expects to record an increase to income tax expense of approximately $15 million (net of federal taxes). The rate increase is not expected to have a material ongoing impact to Exelon s, Generation s and ComEd s future results of operations.

12. 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, 2016 to June 30, 2017:

Nuclear decommissioning ARO at December 31, 2016[(a)]	$ 8,734
Acquisition of FitzPatrick	417
Net increase due to changes in, and timing of, estimated cash flows	103
Accretion expense	225
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at June 30, 2017[(a)(b)]	$ 9,476

(a) Includes $12 million and $10 million for the current portion of the ARO at June 30, 2017 and December 31, 2016, respectively, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets.
(b) Includes the fair value of the FitzPatrick ARO liability as of March 31, 2017, the date of the acquisition. See Note 4 Mergers, Acquisitions and Dispositions.

During the six months ended June 30, 2017, Generation s nuclear ARO increased by approximately $742 million. The increase is largely driven by the acquisition of FitzPatrick and the announced early retirement of TMI. The fair value of FitzPatrick s assets and liabilities, including the ARO, was determined based on significant estimates and assumptions that are judgmental in nature. The fair value of the ARO is considered an initial estimate and will be updated with inputs from a third party engineering firm with corresponding adjustments recorded by the end of 2017. For additional details on the acquisition of FitzPatrick, see Note 4 Mergers, Acquisitions and Dispositions. Included in the $103 million net increase due to changes in, and timing of, estimated cash flows above, is $138 million associated with the May 30, 2017 announcement to early retire the TMI nuclear unit on September 30, 2019. Refer to Note 7 Early Nuclear Plant Retirements for additional information regarding the announced early retirement of TMI. The increase in the ARO liability for TMI incorporates the early shutdown date, increases the probabilities of longer term decommissioning scenarios, and reflects an increase in the estimated costs to decommission based on updated decommissioning cost study reflecting the early retirement of the unit.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment (NDCA) with the PAPUC proposing an annual recovery from customers of approximately $4 million which, if approved by the PAPUC, will be effective January 1, 2018. This amount reflects a decrease from the current approved annual collection of approximately $24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. See Note 16 Asset Retirement Obligations of Exelon s 2016 Form 10-K, for information regarding the amount collected from PECO ratepayers for decommissioning costs.

At June 30, 2017 and December 31, 2016, Exelon and Generation had NDT fund investments totaling $12,641 million and $11,061 million, respectively. The increase is primarily driven by the acquisition of FitzPatrick.

The following table provides unrealized gains on NDT funds for the three and six months ended June 30, 2017 and 2016:

	Exelon and Generation Three Months Ended June 30,		Exelon and Generation Six Months Ended June 30,	
	2017	2016	2017	2016
Net unrealized gains (losses) on decommissioning trust funds Regulatory Agreement Units[(a)]	$ (13)	$ 52	$ 210	$ 131
Net unrealized gains on decommissioning trust funds Non-Regulatory Agreement Units[(b)(c)]	70	48	235	100

(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 gains (losses) related to the Zion Station pledged assets for the three months ended June 30, 2017 and 2016 respectively. Excludes $(2) million and $3 million of net unrealized gains (losses) related to the Zion Station pledged assets for the six months ended June 30, 2017 and 2016, respectively. Net unrealized gains (losses) related to Zion Station pledged assets are included in Other current liabilities and Payable for Zion Station decommissioning on Exelon s and Generation s Consolidated Balance Sheets in 2017 and 2016, respectively.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Interest and dividends on NDT fund investments are recognized when earned and are included in Other, net in 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 within Other, net in Exelon s and Generation s Consolidated Statement of Operations and Comprehensive Income.

Refer to Note 3 Regulatory Matters and Note 27 Related Party Transactions of the Exelon 2016 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 completing certain decommissioning activities at Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 16 Asset Retirement Obligations of the Exelon 2016 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 $114 million which is included within the nuclear decommissioning ARO at June 30, 2017. 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 June 30, 2017 and December 31, 2016:

	Exelon and Generation	
	June 30, 2017	**December 31, 2016**
Carrying value of Zion Station pledged assets	$ 75	$ 113
Payable to Zion Solutions[(a)]	69	104
Current portion of payable to Zion Solutions[(b)]	69	90
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(c)]	914	878

(a) 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) Included in Other current liabilities within Exelon s and Generation s Consolidated Balance Sheets.
(c) 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 EnergySolutions (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 in the March 31, 2017 filing to the PAPUC which, if approved by the PAPUC, will be effective January 1, 2018.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2018 for shutdown reactors and reactors within five years of shutdown. This report will reflect the status of decommissioning funding assurance as of December 31, 2017 and will include the impact of the announced early retirement of TMI. A shortfall could require Exelon to post parental guarantee for Generation s share of the funding assurance. However, the amount of any required guarantee will ultimately depend on the decommissioning approach adopted at TMI, the associated level of costs, and the decommissioning trust fund investment performance going forward.

13. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all employees.

Effective March 31, 2017, in connection with the acquisition of FitzPatrick, Exelon established a new qualified pension plan and a new other postretirement employee benefit plan, and recorded benefit plan obligations of $38 million and $11 million, respectively. Refer to Note 4 Mergers, Acquisitions and Dispositions for additional discussion of the acquisition of FitzPatrick.

Effective March 23, 2016, Exelon became the sponsor of all of PHI s defined benefit pension and other postretirement benefit plans, and assumed PHI s benefit plan obligations and related assets. As a result, PHI s benefit plan net obligation and related regulatory assets were transferred to Exelon.

Defined Benefit Pension and Other Postretirement Benefits

During the first quarter of 2017, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2017. This valuation resulted in an increase to the pension obligation of $92 million and an increase to the other postretirement benefit obligation of $57 million. Additionally, accumulated other comprehensive loss increased by approximately $59 million (after tax), regulatory assets increased by approximately $57 million and regulatory liabilities increased by approximately $4 million.

The majority of the 2017 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 4.04%. The majority of the 2017 other

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.58% for funded plans and a discount rate of 4.04%.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following tables present the components of Exelon s net periodic benefit costs, prior to capitalization, for the three and six months ended June 30, 2017 and 2016 and PHI s net periodic benefit costs, prior to capitalization, for the predecessor period of January 1, 2016 to March 23, 2016.

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2017[(a)]	2016[(b)]	2017[(a)]	2016[(b)]
Components of net periodic benefit cost:				
Service cost	$ 97	$ 91	$ 28	$ 28
Interest cost	211	212	46	48
Expected return on assets	(299)	(292)	(41)	(42)
Amortization of:				
Prior service cost (benefit)	1	4	(47)	(47)
Actuarial loss	150	142	15	16
Settlement charges	2			
Net periodic benefit cost	$ 162	$ 157	$ 1	$ 3

	Pension Benefits Six Months Ended June 30,		Other Postretirement Benefits Six Months Ended June 30,	
	2017[(a)]	2016[(b)]	2017[(a)]	2016[(b)]
Components of net periodic benefit cost:				
Service cost	$ 191	$ 170	$ 54	$ 54
Interest cost	422	403	91	90
Expected return on assets	(598)	(555)	(82)	(80)
Amortization of:				
Prior service cost (benefit)	1	7	(94)	(91)
Actuarial loss	302	269	31	30
Settlement charges	2			
Net periodic benefit cost	$ 320	$ 294	$	$ 3

(a) FitzPatrick net benefit costs are included for the period after acquisition.
(b) PHI net periodic benefit costs for the period prior to the merger are not included in the table above.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Predecessor PHI	
	Pension Benefits January 1, 2016 to March 23, 2016	**Other Postretirement Benefits January 1, 2016 to March 23, 2016**
Components of net periodic benefit cost:		
Service cost	$ 12	$ 1
Interest cost	26	6
Expected return on assets	(30)	(5)
Amortization of:		
Prior service cost (benefit)		(3)
Actuarial loss	14	2
Net periodic benefit cost	$ 22	$ 1

The amounts below represent Exelon s, Generation s, ComEd s, PECO s, BGE s, PHI s, Pepco s, DPL s, ACE s, BSC s and PHISCO s allocated p of the pension and postretirement benefit plan costs, which were included in Property, plant and equipment within the respective Consolidated Balance Sheets and Operating and maintenance expense within the Consolidated Statement of Operations and Comprehensive Income during the three and six months ended June 30, 2017 and 2016 and PHI s for the predecessor and successor periods of January 1, 2016 to March 23, 2016 and March 24, 2016 to June 30, 2016, respectively.

Pension and Other Postretirement Benefit Costs	**Three Months Ended June 30, 2017**	**2016**	**Six Months Ended June 30, 2017**	**2016**
Exelon	$ 163	$ 160	$ 320	$ 297
Generation[c]	59	55	113	109
ComEd	44	42	87	83
PECO	7	8	14	17
BGE	16	18	32	33
BSC[a]	13	10	26	24
Pepco[b]	6	7	13	16
DPL[b]	3	4	6	9
ACE[b]	3	4	7	8
PHISCO[a][b]	12	12	22	21

Pension and Other Postretirement Benefit Costs	*Successor* **Three Months Ended June 30, 2017**	**Three Months Ended June 30, 2016**	**Six Months Ended June 30, 2017**	**March 24, 2016 to June 30, 2016**	*Predecessor* **January 1, 2016 to March 23, 2016**
PHI	$ 24	$ 27	$ 48	$ 31	$ 23

(a) 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.

(b)

Pepco s, DPL s, ACE s and PHISCO s pension and postretirement benefit costs for the six months ended June 30, 2016 include $7 million, $4 million, $3 million and $9 million, respectively, of costs incurred prior to the closing of Exelon s merger with PHI on March 23, 2016.

(c) FitzPatrick net benefit costs are included for the period after acquisition.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and six months ended June 30, 2017 and 2016 and PHI s for the predecessor and successor periods of January 1, 2016 to March 23, 2016 and March 24, 2016 to June 30, 2016, respectively.

	Three Months Ended June 30,		Six Months Ended June 30,	
Savings Plan Matching Contributions	**2017**	**2016**	**2017**	**2016**
Exelon	$ 33	$ 30	$ 63	$ 56
Generation	14	13	28	25
ComEd	8	7	15	13
PECO	2	2	4	4
BGE	3	2	4	3
BSC[(a)]	3	2	5	7
Pepco[(b)]	1	1	2	2
DPL[(b)]	1		1	1
PHISCO[(a)(b)]	1	2	3	3
ACE		1	1	1

	Successor				Predecessor
Savings Plan Matching Contributions	**Three Months Ended June 30, 2017**	**Three Months Ended June 30, 2016**	**Six Months Ended June 30, 2017**	**March 24, 2016 to June 30, 2016**	**January 1, 2016 to March 23, 2016**
PHI	$ 3	$ 4	$ 7	$ 4	$ 3

(a) These amounts primarily represent amounts billed to Exelon and PHI s subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, BGE, Pepco and DPL amounts above.

(b) Pepco s, DPL s and PHISCO s matching contributions for the six months ended June 30, 2016 include $1 million, $1 million and $1 million, respectively, of costs incurred prior to the closing of Exelon s merger with PHI on March 23, 2016, which is not included in Exelon s matching contributions for the six months ended June 30, 2016.

14. Severance (All Registrants)

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan (one-time termination benefits), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Ongoing Severance Plans

The Registrants provide severance and health and welfare benefits under Exelon s ongoing severance benefit plans to terminated employees in the normal course of business. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three and six months ended June 30, 2017 and 2016, Exelon, Generation, ComEd, PHI, Pepco, DPL, and ACE recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income.

	Exelon	Generation[(a)]	ComEd[(a)]	*Successor* PHI	Pepco[(a)]	DPL[(a)]	ACE[(a)]
Three Months Ended							
June 30, 2017	$ 5	$ 1	$ 1	$ 3	$ 1	$ 1	$ 1
June 30, 2016	2	1	1				
Six Months Ended							
June 30, 2017	$ 9	$ 4	$ 2	$ 3	$ 1	$ 1	$ 1
June 30, 2016	4	3	1				

(a) The amounts above for Generation include less than $1 million and $1 million for amounts billed by BSC through intercompany allocations for the three and six months ended June 30, 2017, respectively, and $1 million and $2 million for the three and six months ended June 30, 2016, respectively. The amounts above for ComEd include less than $1 million and $1 million for amounts billed by BSC through intercompany allocations for the three and six months ended June 30, 2017, respectively, and less than $1 million and $1 million for the three and six months ended June 30, 2016, respectively. Amounts billed by PHISCO to Pepco, DPL and ACE were $1 million, each, for both three and six months ended June 30, 2017. Pepco, DPL and ACE did not have any ongoing severance plans for the three and six months ended June 30, 2016.

Cost Management Program-Related Severance

In August 2015, Exelon announced a cost management program focused on cost savings at BSC and Generation, including the elimination of approximately 500 positions. 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. Exelon expects that approximately 250 corporate support positions in BSC and approximately 250 positions located throughout Generation will be eliminated.

For the three months ended June 30, 2017 and 2016, the amounts for severance costs related to the cost management program were immaterial. For the six months ended June 30, 2017 and 2016, the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE
Six Months Ended					
June 30, 2017[(a)]	$ (1)	$ (1)	$	$	$
June 30, 2016[(b)]	$ 17	$ 12	$ 3	$ 1	$ 1

(a) Amounts billed by BSC through intercompany allocations for the six months ended June 30, 2017 were immaterial.
(b) The amounts above for Generation, ComEd, PECO and BGE include $7 million, $3 million, $1 million and $1 million, respectively, for amounts billed by BSC through intercompany allocations for the six months ended June 30, 2016.

Early Plant Retirement-Related Severance (Exelon and Generation)

As a result of the Three Mile Island plant retirement decision, Exelon and Generation will incur certain employee-related costs, including severance benefit costs. Severance costs will be provided to management employees that are eligible under Exelon s severance policy, to the extent that those employees are not redeployed to other locations. In June 2017, Exelon and Generation recognized severance costs of $17 million related to expected management employee severances resulting from the plant retirements within Operating and maintenance expense in their Consolidated Statements of Operation and Comprehensive Income. Approximately half of the employees at this location fall under a collective bargaining union agreement and are not eligible for severance benefits under an existing plan. The union and Exelon will negotiate terms of any severance benefits. If severance benefits are successfully negotiated, the amounts will be accrued as a one-time employee termination benefit once the established plan is communicated to employees. The final amount of the severance cost will ultimately depend on the specific employees severed. See Note 7 Early Nuclear Plant Retirements for additional information regarding the announced early retirement of TMI.

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

Severance Costs Related to the PHI Merger

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. Cash payments under the plan began in May 2016 and will continue through 2020.

Pepco and DPL maintain regulatory assets for merger related integration costs which include a portion of the severance costs related to the PHI merger that is either currently being recovered in rates or is deemed probable of recovery if not currently being recovered in rates. As of June 30, 2017 and 2016, Pepco and DPL have regulatory assets of $12 million and $13 million, respectively, and $9 million and $3 million, respectively.

For the three and six months ended June 30, 2017, the PHI merger severance costs were immaterial. For the three and six months ended June 30, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Three Months Ended June 30, 2016									
Severance costs (benefits)[(a)]	$ 2	$ (1)	$ (1)	$	$	$ 4	$ 2	$ 1	$ 1
Six Months Ended June 30, 2016									
Severance costs[(a)]	$ 55	$ 9	$ 2	$ 1	$ 1	$ 42	$ 20	$ 12	$ 10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE include $(1) million, $(1) million, less than $1 million, less than $1 million, $2 million, $1 million and $1 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the three months ended June 30, 2016, and $8 million, $2 million, $1 million, $1 million, $19 million, $11 million and $10 million for the six months ended June 30, 2016.

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

Severance Liability

Amounts included in the table below represent the severance liability recorded for the severance plans above for employees of each Registrant and exclude amounts included at Exelon and billed through intercompany allocations:

						Successor			
Severance Liability	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Balance at December 31, 2016	$ 88	$ 36	$ 3	$	$				