EXELON CORP
Form 10-Q
October 26, 2016
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Quarterly Period Ended September 30, 2016

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 x 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 x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definition of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

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

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

The number of shares outstanding of each registrant s common stock as of September 30, 2016 was:

Exelon Corporation Common Stock, without par value	923,270,314
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,143
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
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
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
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc.
Other Terms and Abbreviations	
Note of the Exelon 2015 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon s 2015 Annual Report on Form 10-K
Note of the PHI 2015 Form 10-K	Reference to specific Note to Consolidated Financial Statements within Legacy PHI s 2015 Annual Report on Form 10-K
1998 restructuring settlement	PECO s 1998 settlement of its restructuring case mandated by the Competition Act
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
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
ASC	Accounting Standards Codification
BGS	Basic Generation Service (the supply of electricity by ACE to retail customers in New Jersey who have not elected to purchase electricity from a competitive supplier)
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
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
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MDPSC to enter into a contract for new generation
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
CTC	Competitive Transition Charge
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
Default Electricity Supply Revenue	Revenue primarily from Default Electricity Supply
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
EGTP	ExGen Texas Power, LLC
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
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
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	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
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
NOV	Notice of Violation
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
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
PHI Retirement Plan	PHI s noncontributory retirement plan
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant from DOE
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOCAs	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

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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.

FORWARD-LOOKING STATEMENTS

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) Exelon s 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23; (2) PHI s 2015 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 16; (3) 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 18; and (4) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

The public may read and copy any reports or other information that the Registrants file with the SEC at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at www.sec.gov and the Registrants websites at www.exeloncorp.com. Information contained on the Registrants websites shall not be deemed incorporated into, or to be a part of, this Report.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions, except per share data)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Competitive businesses revenues	$ 4,535	$ 4,564	$ 12,243	$ 14,278
Rate-regulated utility revenues	4,467	2,837	11,243	8,468
Total operating revenues	9,002	7,401	23,486	22,746
Operating expenses				
Competitive businesses purchased power and fuel	2,584	2,515	6,599	7,789
Rate-regulated utility purchased power and fuel	1,170	776	2,863	2,421
Operating and maintenance	2,338	1,996	7,677	6,119
Depreciation and amortization	1,195	606	2,821	1,818
Taxes other than income	449	310	1,168	908
Total operating expenses	7,736	6,203	21,128	19,055
Gain on sales of assets	1	2	41	10
Operating income	1,267	1,200	2,399	3,701
Other income and (deductions)				
Interest expense, net	(506)	(243)	(1,148)	(724)
Interest expense to affiliates	(10)	(10)	(31)	(31)
Other, net	120	(244)	377	(179)
Total other income and (deductions)	(396)	(497)	(802)	(934)
Income before income taxes	871	703	1,597	2,767
Income taxes	340	115	625	805
Equity in losses of unconsolidated affiliates	(5)	(1)	(16)	(3)
Net income	526	587	956	1,959
Net income (loss) attributable to noncontrolling interests and preference stock dividends	36	(42)	26	
Net income attributable to common shareholders	$ 490	$ 629	$ 930	$ 1,959
Comprehensive income, net of income taxes				
Net income	$ 526	$ 587	$ 956	$ 1,959
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(12)	(11)	(35)	(35)
Actuarial loss reclassified to periodic benefit cost	47	55	140	165
Pension and non-pension postretirement benefit plan valuation adjustment			(3)	(29)
Unrealized gain (loss) on cash flow hedges	3	(3)	(4)	4

Unrealized loss on equity investments	(4)		(10)	
Unrealized gain (loss) on foreign currency translation	2	(8)	8	(17)
Unrealized loss on marketable securities		(1)		
Other comprehensive income	36	32	96	88
Comprehensive income	562	619	1,052	2,047
Comprehensive income (loss) attributable to noncontrolling interests and preference stock dividends	31	(42)	21	
Comprehensive income attributable to common shareholders	$ 531	$ 661	$ 1,031	$ 2,047
Average shares of common stock outstanding:				
Basic	925	913	924	879
Diluted	927	915	926	883
Earnings per average common share:				
Basic	$ 0.53	$ 0.69	$ 1.01	$ 2.23
Diluted	$ 0.53	$ 0.69	$ 1.00	$ 2.22
Dividends declared per common share	$ 0.32	$ 0.31	$ 0.95	$ 0.93

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)	Nine Months Ended September 30, 2016	2015
Cash flows from operating activities		
Net income	$ 956	$ 1,959
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	4,009	2,930
Impairment of long-lived assets and losses on regulatory assets	274	25
Gain on sales of assets	(41)	(10)
Deferred income taxes and amortization of investment tax credits	623	241
Net fair value changes related to derivatives	100	(363)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(243)	221
Other non-cash operating activities	1,224	856
Changes in assets and liabilities:		
Accounts receivable	(296)	175
Inventories	21	65
Accounts payable and accrued expenses	296	(115)
Option premiums (paid) received, net	(24)	27
Collateral received, net	757	115
Income taxes	527	300
Pension and non-pension postretirement benefit contributions	(283)	(430)
Other assets and liabilities	(537)	(322)
Net cash flows provided by operating activities	7,363	5,674
Cash flows from investing activities		
Capital expenditures	(6,368)	(5,443)
Proceeds from nuclear decommissioning trust fund sales	7,914	4,551
Investment in nuclear decommissioning trust funds	(8,093)	(4,737)
Acquisition of businesses, net of cash acquired	(6,896)	(28)
Proceeds from sales of long-lived assets	49	145
Proceeds from termination of direct financing lease investment	360	
Change in restricted cash	(75)	(70)
Other investing activities	(110)	(107)
Net cash flows used in investing activities	(13,219)	(5,689)
Cash flows from financing activities		
Changes in short-term borrowings	(1,014)	230
Proceeds from short-term borrowings with maturities greater than 90 days	195	
Repayments on short-term borrowings with maturities greater than 90 days	(452)	
Issuance of long-term debt	4,488	5,909
Retirement of long-term debt	(944)	(1,745)
Restricted proceeds from issuance of long-term debt	(30)	
Issuance of common stock		1,868
Redemption of preference stock	(190)	
Dividends paid on common stock	(873)	(819)
Proceeds from employee stock plans	36	24

Other financing activities	35	(65)
Net cash flows provided by financing activities	1,251	5,402
(Decrease) Increase in cash and cash equivalents	(4,605)	5,387
Cash and cash equivalents at beginning of period	6,502	1,878
Cash and cash equivalents at end of period	$ 1,897	$ 7,265

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,897	$ 6,502
Restricted cash and cash equivalents	321	205
Accounts receivable, net		
Customer	4,061	3,187
Other	1,013	912
Mark-to-market derivative assets	754	1,365
Unamortized energy contract assets	126	86
Inventories, net		
Fossil fuel and emission allowances	374	462
Materials and supplies	1,188	1,104
Regulatory assets	1,410	759
Other	1,064	752
Total current assets	12,208	15,334
Property, plant and equipment, net	71,214	57,439
Deferred debits and other assets		
Regulatory assets	10,022	6,065
Nuclear decommissioning trust funds	11,076	10,342
Investments	592	639
Goodwill	6,672	2,672
Mark-to-market derivative assets	669	758
Unamortized energy contract assets	473	484
Pledged assets for Zion Station decommissioning	135	206
Other	1,474	1,445
Total deferred debits and other assets	31,113	22,611
Total assets[(a)]	$ 114,535	$ 95,384

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 567	$ 533
Long-term debt due within one year	2,512	1,500
Accounts payable	3,044	2,883
Accrued expenses	3,236	2,376
Payables to affiliates	8	8
Regulatory liabilities	548	369
Mark-to-market derivative liabilities	222	205
Unamortized energy contract liabilities	452	100
Renewable energy credit obligation	356	302
PHI merger related obligation	145	
Other	1,068	842
Total current liabilities	12,158	9,118
Long-term debt	32,330	23,645
Long-term debt to financing trusts	642	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	18,115	13,776
Asset retirement obligations	9,348	8,585
Pension obligations	3,765	3,385
Non-pension postretirement benefit obligations	1,921	1,618
Spent nuclear fuel obligation	1,023	1,021
Regulatory liabilities	4,437	4,201
Mark-to-market derivative liabilities	422	374
Unamortized energy contract liabilities	927	117
Payable for Zion Station decommissioning	33	90
Other	1,928	1,491
Total deferred credits and other liabilities	41,919	34,658
Total liabilities[(a)]	87,049	68,062
Commitments and contingencies		
Contingently redeemable noncontrolling interests	26	28
Shareholders equity		
Common stock (No par value, 2000 shares authorized, 923 shares and 920 shares outstanding at September 30, 2016 and December 31, 2015, respectively)	18,756	18,676
Treasury stock, at cost (35 shares at September 30, 2016 and December 31, 2015, respectively)	(2,327)	(2,327)
Retained earnings	12,121	12,068
Accumulated other comprehensive loss, net	(2,523)	(2,624)
Total shareholders equity	26,027	25,793
BGE preference stock not subject to mandatory redemption		193
Noncontrolling interests	1,433	1,308
Total equity	27,460	27,294

Total liabilities and shareholders equity	$ 114,535	$ 95,384

(a) Exelon s consolidated assets include $8,514 million and $8,268 million at September 30, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $3,438 million and $3,264 million at September 30, 2016 and December 31, 2015, 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	Preference Stock	Total Shareholders Equity
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294
Net income				930		18	8	956
Long-term incentive plan activity	2,422	61						61
Employee stock purchase plan issuances	924	36						36
Tax benefit on stock compensation		(17)						(17)
Changes in equity of noncontrolling interests						5		5
Adjustment of contingently redeemable noncontrolling interest due to release of contingency						107		107
Common stock dividends				(877)				(877)
Redemption of preference stock							(193)	(193)
Preference stock dividends							(8)	(8)
Other comprehensive income (loss), net of income taxes					101	(5)		96
Balance, September 30, 2016	958,014	$ 18,756	$ (2,327)	$ 12,121	$ (2,523)	$ 1,433	$	$ 27,460

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Operating revenues	$ 4,533	$ 4,562	$ 12,234	$ 14,270
Operating revenues from affiliates	502	206	1,129	571
Total operating revenues	5,035	4,768	13,363	14,841
Operating expenses				
Purchased power and fuel	2,584	2,516	6,599	7,789
Purchased power and fuel from affiliates	5	3	10	11
Operating and maintenance	1,189	1,088	3,855	3,399
Operating and maintenance from affiliates	147	153	478	461
Depreciation and amortization	632	264	1,329	774
Taxes other than income	136	123	380	369
Total operating expenses	4,693	4,147	12,651	12,803
Gain on sales of assets		1	31	7
Operating income	342	622	743	2,045
Other income and (deductions)				
Interest expense, net	(67)	(56)	(243)	(236)
Interest expense to affiliates	(10)	(12)	(30)	(33)
Other, net	185	(257)	395	(193)
Total other income and (deductions)	108	(325)	122	(462)
Income before income taxes	450	297	865	1,583
Income taxes	173	(36)	293	371
Equity in losses of unconsolidated affiliates	(6)	(1)	(16)	(4)
Net income	271	332	556	1,208
Net income (loss) attributable to noncontrolling interests	35	(45)	18	(10)
Net income attributable to membership interest	$ 236	$ 377	$ 538	$ 1,218
Comprehensive income, net of income taxes				
Net income	$ 271	$ 332	$ 556	$ 1,208
Other comprehensive income (loss), net of income taxes				
Unrealized gain (loss) on cash flow hedges	1	(3)	(3)	(7)
Unrealized loss on equity investments			(4)	
Unrealized gain (loss) on foreign currency translation	2	(8)	8	(17)
Unrealized gain (loss) on marketable securities	1	(2)	1	

Other comprehensive income (loss)	4	(13)	2	(24)
Comprehensive income	275	319	558	1,184
Comprehensive income (loss) attributable to noncontrolling interests	30	(45)	13	(10)
Comprehensive income attributable to membership interest	$ 245	$ 364	$ 545	$ 1,194

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
(In millions)	**2016**	**2015**
Cash flows from operating activities		
Net income	$ 556	$ 1,208
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	2,516	1,887
Impairment of long-lived assets	209	1
Gain on sales of assets	(31)	(7)
Deferred income taxes and amortization of investment tax credits	(133)	21
Net fair value changes related to derivatives	112	(252)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(243)	221
Other non-cash operating activities	129	227
Changes in assets and liabilities:		
Accounts receivable	26	252
Receivables from and payables to affiliates, net	(56)	16
Inventories	18	69
Accounts payable and accrued expenses	9	(146)
Option premiums (paid) received, net	(24)	27
Collateral received, net	759	186
Income taxes	202	(70)
Pension and non-pension postretirement benefit contributions	(122)	(189)
Other assets and liabilities	(204)	(245)
Net cash flows provided by operating activities	3,723	3,206
Cash flows from investing activities		
Capital expenditures	(2,651)	(2,774)
Proceeds from nuclear decommissioning trust fund sales	7,914	4,551
Investment in nuclear decommissioning trust funds	(8,093)	(4,737)
Acquisition of businesses	(255)	(28)
Proceeds from sale of long-lived assets	30	144
Change in restricted cash	(39)	(84)
Other investing activities	(184)	(92)
Net cash flows used in investing activities	(3,278)	(3,020)
Cash flows from financing activities		
Proceeds from short-term borrowings with maturities greater than 90 days	195	
Repayments of short-term borrowings with maturities greater than 90 days	(152)	
Issuance of long-term debt	338	1,307
Retirement of long-term debt	(164)	(64)
Retirement of long-term debt to affiliate		(550)
Changes in Exelon intercompany money pool	(785)	1,205
Distribution to member	(167)	(2,368)
Contribution from member	142	55
Other financing activities	92	(6)

Net cash flows used in financing activities	(501)	(421)
Decrease in cash and cash equivalents	(56)	(235)
Cash and cash equivalents at beginning of period	431	780
Cash and cash equivalents at end of period	$ 375	$ 545

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 375	$ 431
Restricted cash and cash equivalents	162	123
Accounts receivable, net		
Customer	2,318	2,095
Other	301	360
Mark-to-market derivative assets	754	1,365
Receivables from affiliates	170	83
Unamortized energy contract assets	126	86
Inventories, net		
Fossil fuel and emission allowances	292	384
Materials and supplies	849	880
Other	788	535
Total current assets	6,135	6,342
Property, plant and equipment, net	26,374	25,843
Deferred debits and other assets		
Nuclear decommissioning trust funds	11,076	10,342
Investments	381	210
Goodwill	47	47
Mark-to-market derivative assets	630	733
Prepaid pension asset	1,621	1,689
Pledged assets for Zion Station decommissioning	135	206
Unamortized energy contract assets	472	484
Deferred income taxes	5	6
Other	692	627
Total deferred debits and other assets	15,059	14,344
Total assets[(a)]	$ 47,568	$ 46,529

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 40	$ 29
Long-term debt due within one year	254	90
Accounts payable	1,465	1,583
Accrued expenses	942	935
Payables to affiliates	118	104
Borrowings from Exelon intercompany money pool	461	1,252
Mark-to-market derivative liabilities	203	182
Unamortized energy contract liabilities	76	100
Renewable energy credit obligation	356	302
Other	392	356
Total current liabilities	4,307	4,933
Long-term debt	8,077	7,936
Long-term debt to affiliate	924	933
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,684	5,845
Asset retirement obligations	9,160	8,431
Non-pension postretirement benefit obligations	932	924
Spent nuclear fuel obligation	1,023	1,021
Payables to affiliates	2,704	2,577
Mark-to-market derivative liabilities	197	150
Unamortized energy contract liabilities	97	117
Payable for Zion Station decommissioning	33	90
Other	691	602
Total deferred credits and other liabilities	20,521	19,757
Total liabilities[(a)]	33,829	33,559
Commitments and contingencies		
Contingently redeemable noncontrolling interests	26	28
Equity		
Member s equity		
Membership interest	9,265	8,997
Undistributed earnings	3,072	2,701
Accumulated other comprehensive loss, net	(56)	(63)
Total member s equity	12,281	11,635
Noncontrolling interests	1,432	1,307
Total equity	13,713	12,942

Total liabilities and equity	$ 47,568	$ 46,529

(a) Generation s consolidated assets include $8,415 million and $8,235 million at September 30, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include $3,196 million and $3,135 million at September 30, 2016 and December 31, 2015, 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, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942
Net income		538		18	556
Changes in equity of noncontrolling interests				5	5
Adjustment of contingently redeemable noncontrolling interests due to release of contingency				107	107
Allocation of tax benefit from member	98				98
Contribution from member	170				170
Distribution to member		(167)			(167)
Other comprehensive income (loss), net of income taxes			7	(5)	2
Balance, September 30, 2016	$ 9,265	$ 3,072	$ (56)	$ 1,432	$ 13,713

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Electric operating revenues	$ 1,493	$ 1,375	$ 4,019	$ 3,706
Operating revenues from affiliates	4	1	12	3
Total operating revenues	1,497	1,376	4,031	3,709
Operating expenses				
Purchased power	435	388	1,104	974
Purchased power from affiliate	19	2	37	17
Operating and maintenance	327	353	950	1,023
Operating and maintenance from affiliate	50	51	163	143
Depreciation and amortization	196	176	574	528
Taxes other than income	82	79	222	225
Total operating expenses	1,109	1,049	3,050	2,910
Gain on sale of assets	1		6	
Operating income	389	327	987	799
Other income and (deductions)				
Interest expense, net	(194)	(80)	(364)	(238)
Interest expense to affiliates	(3)	(3)	(10)	(10)
Other, net	(80)	4	(72)	14
Total other income and (deductions)	(277)	(79)	(446)	(234)
Income before income taxes	112	248	541	565
Income taxes	75	99	244	226
Net income	$ 37	$ 149	$ 297	$ 339
Comprehensive income	$ 37	$ 149	$ 297	$ 339

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Nine Months Ended September 30, 2016	2015
Cash flows from operating activities		
Net income	$ 297	$ 339
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	574	528
Deferred income taxes and amortization of investment tax credits	398	107
Other non-cash operating activities	122	312
Changes in assets and liabilities:		
Accounts receivable	(55)	(114)
Receivables from and payables to affiliates, net	(9)	(23)
Inventories	4	(23)
Accounts payable and accrued expenses	145	(18)
Collateral posted, net	(2)	(43)
Income taxes	206	389
Pension and non-pension postretirement benefit contributions	(35)	(142)
Other assets and liabilities	104	34
Net cash flows provided by operating activities	1,749	1,346
Cash flows from investing activities		
Capital expenditures	(1,950)	(1,670)
Change in restricted cash		2
Other investing activities	31	22
Net cash flows used in investing activities	(1,919)	(1,646)
Cash flows from financing activities		
Changes in short-term borrowings	(284)	300
Issuance of long-term debt	1,200	400
Retirement of long-term debt	(665)	(260)
Contributions from parent	188	75
Dividends paid on common stock	(275)	(226)
Other financing activities	(17)	(4)
Net cash flows provided by financing activities	147	285
Decrease in cash and cash equivalents	(23)	(15)
Cash and cash equivalents at beginning of period	67	66
Cash and cash equivalents at end of period	$ 44	$ 51

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 44	$ 67
Restricted cash	2	2
Accounts receivable, net		
Customer	546	533
Other	259	272
Receivables from affiliates	359	199
Inventories, net	156	164
Regulatory assets	205	218
Other	63	63
Total current assets	1,634	1,518
Property, plant and equipment, net	18,811	17,502
Deferred debits and other assets		
Regulatory assets	987	895
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,238	2,172
Prepaid pension asset	1,387	1,490
Other	332	324
Total deferred debits and other assets	7,575	7,512
Total assets	$ 28,020	$ 26,532

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 10	$ 294
Long-term debt due within one year	425	665
Accounts payable	625	660
Accrued expenses	1,045	706
Payables to affiliates	57	62
Customer deposits	126	131
Regulatory liabilities	204	155
Mark-to-market derivative liability	19	23
Other	78	70
Total current liabilities	2,589	2,766
Long-term debt	6,606	5,844
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,320	4,914
Asset retirement obligations	118	111
Non-pension postretirement benefits obligations	244	259
Regulatory liabilities	3,577	3,459
Mark-to-market derivative liability	225	224
Other	526	507
Total deferred credits and other liabilities	10,010	9,474
Total liabilities	19,410	18,289
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	6,022	5,677
Retained earnings	1,000	978
Total shareholders equity	8,610	8,243
Total liabilities and shareholders equity	$ 28,020	$ 26,532

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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, 2015	$ 1,588	$ 5,677	$ (1,639)	$ 2,617	$ 8,243
Net income			297		297
Appropriation of retained earnings for future dividends			(297)	297	
Common stock dividends				(275)	(275)
Contribution from parent		188			188
Parent tax matter indemnification		157			157
Balance, September 30, 2016	$ 1,588	$ 6,022	$ (1,639)	$ 2,639	$ 8,610

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2016**	**2015**	**2016**	**2015**
Operating revenues				
Electric operating revenues	$ 738	$ 691	$ 1,966	$ 1,950
Natural gas operating revenues	48	48	322	435
Operating revenues from affiliates	2	1	5	1
Total operating revenues	788	740	2,293	2,386
Operating expenses				
Purchased power	171	207	466	584
Purchased fuel	10	10	110	198
Purchased power from affiliate	91	61	233	171
Operating and maintenance	168	166	501	529
Operating and maintenance from affiliates	31	30	103	80
Depreciation and amortization	67	68	201	198
Taxes other than income	46	44	126	125
Total operating expenses	584	586	1,740	1,885
Gain on sales of assets				1
Operating income	204	154	553	502
Other income and (deductions)				
Interest expense, net	(27)	(25)	(83)	(75)
Interest expense to affiliates	(3)	(3)	(9)	(9)
Other, net	2	1	6	3
Total other income and (deductions)	(28)	(27)	(86)	(81)
Income before income taxes	176	127	467	421
Income taxes	54	37	121	122
Net income attributable to common shareholder	$ 122	$ 90	$ 346	$ 299
Comprehensive income	$ 122	$ 90	$ 346	$ 299

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
(In millions)	**2016**	**2015**
Cash flows from operating activities		
Net income	$ 346	$ 299
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	201	198
Deferred income taxes and amortization of investment tax credits	69	11
Other non-cash operating activities	49	69
Changes in assets and liabilities:		
Accounts receivable	(50)	(15)
Receivables from and payables to affiliates, net	9	
Inventories	5	8
Accounts payable and accrued expenses	(12)	(19)
Income taxes	43	69
Pension and non-pension postretirement benefit contributions	(29)	(37)
Other assets and liabilities	(49)	(16)
Net cash flows provided by operating activities	582	567
Cash flows from investing activities		
Capital expenditures	(448)	(435)
Change in restricted cash		(1)
Other investing activities	10	11
Net cash flows used in investing activities	(438)	(425)
Cash flows from financing activities		
Issuance of long-term debt	300	
Restricted proceeds from issuance of long-term debt	(30)	
Changes in Exelon intercompany money pool		55
Contributions from parent	18	16
Dividends paid on common stock	(208)	(209)
Other financing activities	(3)	(2)
Net cash flows provided by (used in) financing activities	77	(140)
Increase in cash and cash equivalents	221	2
Cash and cash equivalents at beginning of period	295	30
Cash and cash equivalents at end of period	$ 516	$ 32

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 516	$ 295
Restricted cash and cash equivalents	33	3
Accounts receivable, net		
Customer	271	258
Other	132	146
Receivables from affiliates	3	2
Inventories, net		
Fossil fuel	38	43
Materials and supplies	26	26
Prepaid utility taxes	43	11
Regulatory assets	37	34
Other	22	24
Total current assets	1,121	842
Property, plant and equipment, net	7,400	7,141
Deferred debits and other assets		
Regulatory assets	1,651	1,583
Investments	26	28
Receivable from affiliates	466	405
Prepaid pension asset	353	347
Other	24	21
Total deferred debits and other assets	2,520	2,384
Total assets	$ 11,041	$ 10,367

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$ 300	$ 300
Accounts payable	282	281
Accrued expenses	108	109
Payables to affiliates	64	55
Customer deposits	60	58
Regulatory liabilities	128	112
Other	26	29
Total current liabilities	968	944
Long-term debt	2,579	2,280
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,964	2,792
Asset retirement obligations	28	27
Non-pension postretirement benefits obligations	288	287
Regulatory liabilities	551	527
Other	87	90
Total deferred credits and other liabilities	3,918	3,723
Total liabilities	7,649	7,131
Commitments and contingencies		
Shareholder s equity		
Common stock	2,473	2,455
Retained earnings	918	780
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,392	3,236
Total liabilities and shareholder s equity	$ 11,041	$ 10,367

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder s Equity
Balance, December 31, 2015	$ 2,455	$ 780	$ 1	$ 3,236
Net income		346		346
Common stock dividends		(208)		(208)
Allocation of tax benefit from parent	18			18
Balance, September 30, 2016	$ 2,473	$ 918	$ 1	$ 3,392

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Electric operating revenues	$ 733	$ 656	$ 1,993	$ 1,910
Natural gas operating revenues	72	66	412	468
Operating revenues from affiliates	7	3	16	10
Total operating revenues	812	725	2,421	2,388
Operating expenses				
Purchased power	164	159	399	497
Purchased fuel	14	11	109	167
Purchased power from affiliate	182	141	486	373
Operating and maintenance	150	138	494	412
Operating and maintenance from affiliates	28	31	94	87
Depreciation and amortization	101	79	307	271
Taxes other than income	58	57	172	169
Total operating expenses	697	616	2,061	1,976
Gain on sale of assets		1		1
Operating income	115	110	360	413
Other income and (deductions)				
Interest expense, net	(24)	(21)	(64)	(62)
Interest expense to affiliates	(4)	(4)	(12)	(11)
Other, net	5	4	16	13
Total other income and (deductions)	(23)	(21)	(60)	(60)
Income before income taxes	92	89	300	353
Income taxes	36	35	109	141
Net income	56	54	191	212
Preference stock dividends	2	3	8	10
Net income attributable to common shareholder	$ 54	$ 51	$ 183	$ 202
Comprehensive income	$ 56	$ 54	$ 191	$ 212
Comprehensive income attributable to preference stock dividends	2	3	8	10
Comprehensive income attributable to common shareholder	$ 54	$ 51	$ 183	$ 202

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
(In millions)	**2016**	**2015**
Cash flows from operating activities		
Net income	$ 191	$ 212
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	307	271
Impairment of long-lived assets and losses on regulatory assets	52	
Deferred income taxes and amortization of investment tax credits	54	79
Other non-cash operating activities	109	111
Changes in assets and liabilities:		
Accounts receivable	(50)	62
Receivables from and payables to affiliates, net	(10)	(8)
Inventories	(7)	10
Accounts payable and accrued expenses	43	34
Collateral posted, net		(27)
Income taxes	19	(6)
Pension and non-pension postretirement benefit contributions	(46)	(14)
Other assets and liabilities	(2)	(28)
Net cash flows provided by operating activities	660	696
Cash flows from investing activities		
Capital expenditures	(611)	(506)
Change in restricted cash	(22)	2
Other investing activities	19	13
Net cash flows used in investing activities	(614)	(491)
Cash flows from financing activities		
Changes in short-term borrowings	(210)	(70)
Issuance of long-term debt	850	
Retirement of long-term debt	(39)	(37)
Redemption of preference stock	(190)	
Dividends paid on preference stock	(8)	(10)
Dividends paid on common stock	(134)	(116)
Contributions from parent	28	6
Other financing activities	(11)	(15)
Net cash flows provided by (used in) financing activities	286	(242)
Increase (Decrease) in cash and cash equivalents	332	(37)
Cash and cash equivalents at beginning of period	9	64
Cash and cash equivalents at end of period	$ 341	$ 27

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 341	$ 9
Restricted cash and cash equivalents	46	24
Accounts receivable, net		
Customer	332	300
Other	100	112
Inventories, net		
Gas held in storage	37	36
Materials and supplies	39	33
Prepaid utility taxes		61
Regulatory assets	214	267
Other	5	3
Total current assets	1,114	845
Property, plant and equipment, net	6,904	6,597
Deferred debits and other assets		
Regulatory assets	508	514
Investments	12	12
Prepaid pension asset	310	319
Other	9	8
Total deferred debits and other assets	839	853
Total assets[a]	$ 8,857	$ 8,295

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016 (Unaudited)	December 31, 2015
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$	$ 210
Long-term debt due within one year	381	378
Accounts payable	239	209
Accrued expenses	144	110
Payables to affiliates	42	52
Customer deposits	108	102
Regulatory liabilities	54	38
Other	35	35
Total current liabilities	1,003	1,134
Long-term debt	2,281	1,480
Long-term debt to financing trust	252	252
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,149	2,081
Asset retirement obligations	21	17
Non-pension postretirement benefits obligations	204	209
Regulatory liabilities	118	184
Other	72	61
Total deferred credits and other liabilities	2,564	2,552
Total liabilities[(a)]	6,100	5,418
Commitments and contingencies		
Shareholders equity		
Common stock	1,388	1,367
Retained earnings	1,369	1,320
Total shareholders equity	2,757	2,687
Preference stock not subject to mandatory redemption		190
Total equity	2,757	2,877
Total liabilities and shareholders equity	$ 8,857	$ 8,295

(a) BGE s consolidated assets include $47 million and $26 million at September 30, 2016 and December 31, 2015, respectively, of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include $83 million and $122 million at September 30, 2016 and December 31, 2015, respectively, of BGE s consolidated VIE for which the VIE creditors do not have recourse to

BGE. 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	Preference Stock Not Subject To Mandatory Redemption	Total Equity
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$ 2,877
Net income		191	191		191
Preference stock dividends		(8)	(8)		(8)
Common stock dividends		(134)	(134)		(134)
Distribution to parent	(7)		(7)		(7)
Contribution from parent	28		28		28
Redemption of preference stock				(190)	(190)
Balance, September 30, 2016	$ 1,388	$ 1,369	$ 2,757	$	$ 2,757

See the Combined Notes to Consolidated Financial Statements

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	*Successor* Three Months Ended September 30, 2016	*Predecessor* Three Months Ended September 30, 2015	*Successor* March 24 to September 30, 2016	*Predecessor* January 1 to March 23, 2016	*Predecessor* Nine Months Ended September 30, 2015
Operating revenues					
Electric operating revenues	$ 1,366	$ 1,317	$ 2,485	$ 1,096	$ 3,680
Natural gas operating revenues	17	19	46	57	129
Operating revenues from affiliates	11		34		
Total operating revenues	1,394	1,336	2,565	1,153	3,809
Operating expenses					
Purchased power	370	570	658	471	1,575
Purchased fuel	6	9	17	26	71
Purchased power and fuel from affiliates	207		362		
Operating and maintenance	200	287	870	294	875
Operating and maintenance from affiliates	26		51		
Depreciation, amortization and accretion	182	166	355	152	474
Taxes other than income	124	120	248	105	349
Total operating expenses	1,115	1,152	2,561	1,048	3,344
Operating income	279	184	4	105	465
Other income and (deductions)					
Interest expense, net	(64)	(71)	(135)	(65)	(211)
Other, net	19	27	31	(4)	48
Total other income and (deductions)	(45)	(44)	(104)	(69)	(163)
Income (loss) before income taxes	234	140	(100)	36	302
Income taxes	68	49	(9)	17	105
Net income (loss) attributable to membership interest/common shareholders	$ 166	$ 91	$ (91)	$ 19	$ 197
Comprehensive income (loss), net of income taxes					
Net income (loss)	$ 166	$ 91	$ (91)	$ 19	$ 197
Other comprehensive income, net of income taxes					
Pension and non-pension postretirement benefit plans:					
Actuarial loss reclassified to periodic cost				1	4
Unrealized loss on cash flow hedges		1			1
Other comprehensive income		1		1	5
Comprehensive income (loss)	$ 166	$ 92	$ (91)	$ 20	$ 202

See the Combined Notes to Consolidated Financial Statements

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Successor	*Predecessor*	
(In millions)	**March 24 to September 30, 2016**	**January 1 to March 23, 2016**	**Nine Months Ended September 30, 2015**
Cash flows from operating activities			
Net (loss) income	$ (91)	$ 19	$ 197
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	355	152	474
Deferred income taxes and amortization of investment tax credits	237	19	107
Net fair value changes related to derivatives		18	(15)
Other non-cash operating activities	441	46	143
Changes in assets and liabilities:			
Accounts receivable	(94)	(28)	(211)
Receivables from and payables to affiliates, net	39		
Inventories		(4)	(5)
Accounts payable and accrued expenses	(23)	42	23
Collateral received, net		1	
Income taxes	(57)	12	12
Pension and non-pension postretirement benefit contributions	(13)	(4)	(12)
Other assets and liabilities	(248)	(9)	(112)
Net cash flows provided by operating activities	546	264	601
Cash flows from investing activities			
Capital expenditures	(624)	(273)	(855)
Proceeds from sales of long-lived assets	19		
Changes in restricted cash	(39)	3	6
Purchases of investments		(68)	
Other investing activities	13	(5)	14
Net cash flows used in investing activities	(631)	(343)	(835)
Cash flows from financing activities			
Changes in short-term borrowings	(520)	(121)	99
Proceeds from short-term borrowings with maturities greater than 90 days		500	300
Repayments of short-term borrowings with maturities greater than 90 days	(300)		
Issuance of long-term debt	2		408
Retirement of long-term debt	(29)	(11)	(163)
Issuance of preferred stock			54
Dividends paid on common stock			(206)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation		2	23
Distribution to member	(174)		
Contribution from member	1,088		
Change in Exelon intercompany money pool	1		
Other financing activities	(3)	2	(24)

Net cash flows provided by financing activities	65	372	491
(Decrease) Increase in cash and cash equivalents	(20)	293	257
Cash and cash equivalents at beginning of period	319	26	15
Cash and cash equivalents at end of period	$ 299	$ 319	$ 272

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	*Successor* **September 30, 2016**	*Predecessor* **December 31, 2015**
ASSETS		
Current assets		
Cash and cash equivalents	$ 299	$ 26
Restricted cash and cash equivalents	49	14
Accounts receivable, net		
Customer	595	581
Other	345	319
Mark-to-market derivative asset		18
Inventories, net		
Gas held in storage	8	9
Materials and supplies	118	122
Regulatory assets	650	305
Other	54	80
Total current assets	2,118	1,474
Property, plant and equipment, net	11,311	10,864
Deferred debits and other assets		
Regulatory assets	2,945	2,277
Investments	132	80
Goodwill	4,000	1,406
Long-term note receivable	4	4
Prepaid pension asset	470	
Deferred income taxes	7	14
Other	76	69
Total deferred debits and other assets	7,634	3,850
Total assets[a]	$ 21,063	$ 16,188

See the Combined Notes to Consolidated Financial Statements

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	*Successor* **September 30, 2016**	*Predecessor* **December 31, 2015**
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 517	$ 958
Long-term debt due within one year	545	456
Accounts payable	335	404
Accrued expenses	325	266
Payables to affiliates	90	
Unamortized energy contract liabilities	376	
Borrowings from Exelon intercompany money pool	7	
Customer deposits	125	107
Merger related obligation	90	
Regulatory liabilities	101	66
Other	36	70
Total current liabilities	2,547	2,327
Long-term debt	5,499	4,823
Deferred credits and other liabilities		
Regulatory liabilities	167	147
Deferred income taxes and unamortized investment tax credits	3,746	3,406
Asset retirement obligations	14	8
Pension obligations		466
Non-pension postretirement benefit obligations	139	215
Unamortized energy contract liabilities	830	
Other	234	200
Total deferred credits and other liabilities	5,130	4,442
Total liabilities[a]	13,176	11,592
Commitments and contingencies		
Preferred stock[b]		183
Member s equity/Shareholders equity		
Membership interest/Common stock[c]	7,978	3,832
Undistributed (losses)/Retained earnings	(91)	617
Accumulated other comprehensive loss, net		(36)
Total member s equity/shareholders equity	7,887	4,413
Total liabilities and member s equity/shareholders equity	$ 21,063	$ 16,188

(a) PHI s consolidated total assets include $51 million and $30 million at September 30, 2016 and December 31, 2015, respectively, of PHI s consolidated VIE that can only be used to settle the liabilities of the VIE. PHI s consolidated total liabilities include $156 million and $172 million at September 30, 2016 and December 31, 2015, respectively, of PHI s consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 3 Variable Interest Entities.

(b) At December 31, 2015, PHI had 18,000 shares of Series A preferred stock outstanding, par value $0.01 per share.

(c) At December 31, 2015, PHI s (predecessor) shareholders equity included $3,829 million of other paid-in capital and $3 million of common stock. At December 31, 2015, PHI had 400,000,000 shares of common stock authorized and 254,289,261 shares of common stock outstanding, par value $0.01 per share.

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PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

(In millions)	Common Stock/ Membership Interest[(a)]	Retained Earnings/ Undistributed Losses	Accumulated Other Comprehensive Loss, net	Total Shareholders / Member s Equity
Predecessor				
Balance at December 31, 2015	$ 3,832	$ 617	$ (36)	$ 4,413
Net income		19		19
Original issue shares, net	3			3
Net activity related to stock-based awards	3			3
Other comprehensive income, net of income taxes			1	1
Balance at March 23, 2016	$ 3,838	$ 636	$ (35)	$ 4,439
Successor				
Balance at March 24, 2016[(b)]	$ 7,200	$	$	$ 7,200
Net loss		(91)		(91)
Distribution to member[(c)]	(301)			(301)
Contribution from member	1,088			1,088
Distribution of net retirement benefit obligation to member	53			53
Assumption of member liabilities[(d)]	(62)			(62)
Balance at September 30, 2016	$ 7,978	$ (91)	$	$ 7,887

(a) At March 23, 2016 and December 31, 2015, PHI s (predecessor) shareholders equity included $3,835 million and $3,829 million of other paid-in capital, and $3 million and $3 million of common stock, respectively.

(b) The March 24, 2016, beginning balance differs from the PHI Merger total purchase price by $59 million related to an acquisition accounting adjustment recorded at Exelon Corporate to reflect unitary state income tax consequences of the merger.

(c) Distribution to member includes $235 million of net assets associated with PHI s unregulated business interests and $66 million of cash, each of which were distributed by PHI to Exelon.

(d) The liabilities assumed include $29 million for PHI stock-based compensation awards and $33 million for a merger related obligation, each assumed by PHI from Exelon. See Note 4 Mergers, Acquisitions and Dispositions.

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POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Electric operating revenues	$ 634	$ 591	$ 1,692	$ 1,637
Operating revenues from affiliates	1	1	3	4
Total operating revenues	635	592	1,695	1,641
Operating expenses				
Purchased power	84	200	340	573
Purchased power from affiliates	129		223	
Operating and maintenance	100	110	488	324
Operating and maintenance from affiliates	9	1	20	3
Depreciation and amortization	76	66	221	191
Taxes other than income	105	100	287	289
Total operating expenses	503	477	1,579	1,380
Gain on sale of assets			8	
Operating income	132	115	124	261
Other income and (deductions)				
Interest expense, net	(30)	(31)	(98)	(92)
Other, net	12	8	28	21
Total other income and (deductions)	(18)	(23)	(70)	(71)
Income before income taxes	114	92	54	190
Income taxes	35	32	34	62
Net income attributable to common shareholder	$ 79	$ 60	$ 20	$ 128
Comprehensive income	$ 79	$ 60	$ 20	$ 128

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POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Nine Months Ended September 30, 2016	2015
Cash flows from operating activities		
Net income	$ 20	$ 128
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation and amortization	221	191
Deferred income taxes and amortization of investment tax credits	96	70
Other non-cash operating activities	168	42
Changes in assets and liabilities:		
Accounts receivable	(105)	(113)
Receivables from and payables to affiliates, net	44	2
Inventories	3	(5)
Accounts payable and accrued expenses	7	(1)
Income taxes	139	
Pension and non-pension postretirement benefit contributions	(6)	(7)
Other assets and liabilities	(83)	(94)
Net cash flows provided by operating activities	504	213
Cash flows from investing activities		
Capital expenditures	(392)	(374)
Proceeds from sale of long-lived asset	12	
Purchases of investments	(32)	
Changes in restricted cash	(31)	3
Other investing activities	8	14
Net cash flows used in investing activities	(435)	(357)
Cash flows from financing activities		
Changes in short-term borrowings	(64)	(56)
Issuance of long-term debt	2	208
Retirement of long-term debt	(5)	(17)
Dividends paid on common stock	(92)	(91)
Contribution from parent	187	112
Other financing activities		(8)
Net cash flows provided by financing activities	28	148
Increase in cash and cash equivalents	97	4
Cash and cash equivalents at beginning of period	5	6
Cash and cash equivalents at end of period	$ 102	$ 10

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POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 102	$ 5
Restricted cash and cash equivalents	33	2
Accounts receivable, net		
Customer	292	230
Other	148	261
Inventories, net	63	67
Regulatory assets	122	140
Other	4	21
Total current assets	764	726
Property, plant and equipment, net	5,409	5,162
Deferred debits and other assets		
Regulatory assets	676	661
Investments	100	68
Prepaid pension asset	266	287
Other	4	4
Total deferred debits and other assets	1,046	1,020
Total assets	$ 7,219	$ 6,908

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POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$	$ 64
Long-term debt due within one year	12	11
Accounts payable	139	145
Accrued expenses	145	119
Payables to affiliates	74	30
Customer deposits	53	46
Regulatory liabilities	20	15
Merger related obligation	63	
Other	14	25
Total current liabilities	520	455
Long-term debt	2,338	2,340
Deferred credits and other liabilities		
Regulatory liabilities	24	29
Deferred income taxes and unamortized investment tax credits	1,845	1,723
Non-pension postretirement benefit obligations	46	49
Other	124	72
Total deferred credits and other liabilities	2,039	1,873
Total liabilities	4,897	4,668
Commitments and contingencies		
Shareholder s equity		
Common stock	1,309	1,122
Retained earnings	1,013	1,118
Total shareholder s equity	2,322	2,240
Total liabilities and shareholder s equity	$ 7,219	$ 6,908

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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, 2015	$ 1,122	$ 1,118	$ 2,240
Net Income		20	20
Common stock dividends		(125)	(125)
Contribution from parent	187		187
Balance, September 30, 2016	$ 1,309	$ 1,013	$ 2,322

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DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Electric operating revenues	$ 312	$ 294	$ 866	$ 871
Natural gas operating revenues	17	19	102	129
Operating revenues from affiliates	2	1	6	4
Total operating revenues	331	314	974	1,004
Operating expenses				
Purchased power	81	143	297	435
Purchased fuel	6	8	41	65
Purchased power from affiliate	63		110	
Operating and maintenance	50	77	327	233
Operating and maintenance from affiliates	5		11	1
Depreciation, amortization and accretion	44	40	120	113
Taxes other than income	14	14	42	39
Total operating expenses	263	282	948	886
Gain on sale of asset	4		4	
Operating income	72	32	30	118
Other income and (deductions)				
Interest expense, net	(12)	(12)	(37)	(37)
Other, net	3	4	9	8
Total other income and (deductions)	(9)	(8)	(28)	(29)
Income before income taxes	63	24	2	89
Income taxes	19	9	18	34
Net income (loss) attributable to common shareholder	$ 44	$ 15	$ (16)	$ 55
Comprehensive income (loss)	$ 44	$ 15	$ (16)	$ 55

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DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Nine Months Ended September 30, 2016**	**2015**
Cash flows from operating activities		
Net (loss) income	$ (16)	$ 55
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	120	113
Deferred income taxes and amortization of investment tax credits	69	40
Other non-cash operating activities	99	31
Changes in assets and liabilities:		
Accounts receivable	8	(33)
Receivables from and payables to affiliates, net	12	5
Inventories		4
Accounts payable and accrued expenses	(8)	(5)
Collateral received	1	
Income taxes	52	
Other assets and liabilities	(70)	(22)
Net cash flows provided by operating activities	267	188
Cash flows from investing activities		
Capital expenditures	(260)	(246)
Proceeds from sale of long-lived asset	4	
Changes in restricted cash		5
Other investing activities	2	1
Net cash flows used in investing activities	(254)	(240)
Cash flows from financing activities		
Changes in short-term borrowings	(88)	(40)
Issuance of long-term debt		200
Retirement of long-term debt		(100)
Dividends paid on common stock	(39)	(80)
Contribution from parent	113	75
Other financing activities		(2)
Net cash flows (used in) provided by financing activities	(14)	53
(Decrease) Increase in cash and cash equivalents	(1)	1
Cash and cash equivalents at beginning of period	5	4
Cash and cash equivalents at end of period	$ 4	$ 5

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DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 4	$ 5
Accounts receivable, net		
Customer	134	154
Other	44	96
Inventories, net		
Gas held in storage	8	8
Materials and supplies	32	32
Regulatory assets	62	72
Other	17	21
Total current assets	301	388
Property, plant and equipment, net	3,222	3,070
Deferred debits and other assets		
Regulatory assets	297	299
Goodwill	8	8
Prepaid pension asset	188	202
Other	7	2
Total deferred debits and other assets	500	511
Total assets	$ 4,023	$ 3,969

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DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$ 17	$ 105
Long-term debt due within one year	218	204
Accounts payable	74	109
Accrued expenses	47	31
Payables to affiliates	34	20
Customer deposits	37	31
Regulatory liabilities	46	49
Merger related obligation	12	
Other	10	15
Total current liabilities	495	564
Long-term debt	1,047	1,061
Deferred credits and other liabilities		
Regulatory liabilities	100	111
Deferred income taxes and unamortized investment tax credits	1,016	945
Non-pension postretirement benefit obligations	19	19
Other	51	32
Total deferred credits and other liabilities	1,186	1,107
Total liabilities	2,728	2,732
Commitments and contingencies		
Shareholder s equity		
Common stock	725	612
Retained earnings	570	625
Total shareholder s equity	1,295	1,237
Total liabilities and shareholder s equity	$ 4,023	$ 3,969

See the Combined Notes to Financial Statements

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, 2015	$ 612	$ 625	$ 1,237
Net loss		(16)	(16)
Common stock dividends		(39)	(39)
Contribution from parent	113		113
Balance, September 30, 2016	$ 725	$ 570	$ 1,295

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Operating revenues				
Electric operating revenues	$ 420	$ 385	$ 979	$ 1,001
Operating revenues from affiliates	1	1	3	2
Total operating revenues	421	386	982	1,003
Operating expenses				
Purchased power	206	214	491	552
Purchased power from affiliates	15		29	
Operating and maintenance	62	69	336	205
Operating and maintenance from affiliates	5	1	10	2
Depreciation, amortization and accretion	49	49	130	135
Taxes other than income	1	2	6	5
Total operating expenses	338	335	1,002	899
Gain on sale of assets			1	
Operating income (loss)	83	51	(19)	104
Other income and (deductions)				
Interest expense, net	(15)	(16)	(47)	(48)
Other, net	2	1	8	4
Total other income and (deductions)	(13)	(15)	(39)	(44)
Income (loss) before income taxes	70	36	(58)	60
Income taxes	23	14	(8)	23
Net income (loss) attributable to common shareholder	$ 47	$ 22	$ (50)	$ 37
Comprehensive income (loss)	$ 47	$ 22	$ (50)	$ 37

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Nine Months Ended September 30, 2016**	**2015**
Cash flows from operating activities		
Net (loss) income	$ (50)	$ 37
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	130	135
Deferred income taxes and amortization of investment tax credits	14	13
Other non-cash operating activities	138	27
Changes in assets and liabilities:		
Accounts receivable	(32)	(87)
Receivables from and payables to affiliates, net	9	1
Inventories	(1)	(1)
Accounts payable and accrued expenses	10	35
Income taxes	184	10
Other assets and liabilities	(87)	8
Net cash flows provided by operating activities	315	178
Cash flows from investing activities		
Capital expenditures	(227)	(212)
Proceeds from sale of long-lived asset	2	
Changes in restricted cash	(4)	(6)
Other investing activities	2	2
Net cash flows used in investing activities	(227)	(216)
Cash flows from financing activities		
Changes in short-term borrowings	(5)	98
Retirement of long-term debt	(35)	(46)
Dividends paid on common stock	(24)	(12)
Contribution from parent	139	
Other financing activities	(1)	
Net cash flows provided by financing activities	74	40
Increase in cash and cash equivalents	162	2
Cash and cash equivalents at beginning of period	3	2
Cash and cash equivalents at end of period	$ 165	$ 4

See the Combined Notes to Consolidated Financial Statements

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	**September 30, 2016**	**December 31, 2015**
ASSETS		
Current assets		
Cash and cash equivalents	$ 165	$ 3
Restricted cash and cash equivalents	15	12
Accounts receivable, net		
Customer	168	156
Other	46	242
Receivables from affiliates	2	
Inventories, net	22	23
Prepaid utility taxes	10	
Regulatory assets	89	98
Other	3	12
Total current assets	520	546
Property, plant and equipment, net	2,456	2,322
Deferred debits and other assets		
Regulatory assets	412	414
Long-term note receivable	4	4
Prepaid pension asset	73	82
Other	42	19
Total deferred debits and other assets	531	519
Total assets[(a)]	$ 3,507	$ 3,387

See the Combined Notes to Consolidated Financial Statements

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	September 30, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$	$ 5
Long-term debt due within one year	38	48
Accounts payable	110	96
Accrued expenses	72	70
Payables to affiliates	27	16
Customer deposits	35	30
Regulatory liabilities	35	18
Merger related obligation	14	
Other	7	14
Total current liabilities	338	297
Long-term debt	1,129	1,153
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	908	885
Non-pension postretirement benefit obligations	35	33
Regulatory liabilities	1	7
Other	31	12
Total deferred credits and other liabilities	975	937
Total liabilities[(a)]	2,442	2,387
Commitments and contingencies		
Shareholder s equity		
Common stock	912	773
Retained earnings	153	227
Total shareholder s equity	1,065	1,000
Total liabilities and shareholder s equity	$ 3,507	$ 3,387

(a) ACE s consolidated total assets include $34 million and $30 million at September 30, 2016 and December 31, 2015, respectively, of ACE s consolidated VIE that can only be used to settle the liabilities of the VIE. ACE s consolidated total liabilities include $139 million and $172 million at September 30, 2016 and December 31, 2015, respectively, of ACE s consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2015	$ 773	$ 227	$ 1,000
Net loss		(50)	(50)
Common stock dividends		(24)	(24)
Contribution from parent	139		139
Balance, September 30, 2016	$ 912	$ 153	$ 1,065

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. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution and transmission businesses. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

regulated retail sale of natural gas and the provision of natural gas distribution services in central Maryland, including the City of Baltimore.

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)

Pursuant to 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 the 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 that had solely related to PHI, Pepco, DPL or ACE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are named specifically for their related activities and disclosures.

Certain prior year amounts in the Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows of PHI, Pepco, DPL and ACE have been reclassified to conform the presentation of these amounts to the current period presentation in Exelon s financial statements. Most significantly for PHI, Pepco, DPL and ACE, current regulatory assets and liabilities have been presented separately from the non-current portions in each respective Consolidated Balance Sheet where recovery or refund is expected within the next 12 months. Additionally, for PHI, Pepco, DPL and ACE, the removal cost within Accumulated depreciation was reclassified to the Regulatory liability or Regulatory asset account to align with Exelon s presentation. The reclassifications were not considered errors for PHI, Pepco, DPL or ACE.

In its December 31, 2015 Form 10-K, Exelon revised the presentation on the Consolidated Statements of Operations and Comprehensive Income for PECO and BGE to reflect separately operating revenues from the sale of electricity and operating revenues from the sale of natural gas, as well as to reflect separately purchased power expense and purchased fuel expense within the operating expenses section of the Consolidated Statement of Operations and Comprehensive Income. Further, Exelon revised the presentation from Total operating revenues to Rate-regulated utility revenues and Competitive businesses revenues on the face of Exelon s Consolidated Statement of Operations and Comprehensive Income for all periods presented. Similarly, Exelon has separately

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

presented Rate-regulated utility purchased power and fuel expense and Competitive businesses purchased power and fuel expense on the face of Exelon s Consolidated Statement of Operations and Comprehensive Income for all periods presented. The reclassifications described herein were made for presentation purposes and did not affect any of the Registrants total operating revenues or net income.

ACE Basic Generation Service Recovery Mechanism

ACE has a recovery mechanism for purchased power costs associated with BGS. ACE records a deferred energy supply costs regulatory asset or regulatory liability for under or over-recovered costs that are expected to be recovered from or refunded to ACE customers, respectively. In the first quarter of 2016, ACE changed its method of accounting for determining under or over-recovered costs in this recovery mechanism to include unbilled revenues in the determination of under or over-recovered costs. ACE believes this change is preferable as it better reflects the economic impacts of dollar-for-dollar cost recovery mechanisms. ACE applied the change retrospectively. The impact of the change was a $12 million reduction to ACE s opening Retained earnings as of January 1, 2014 with a corresponding reduction to Regulatory assets. The impact of the change on Net income attributable to common shareholder was an increase of $8 million and $9 million for the three and nine months ended September 30, 2015, respectively.

Classification of Interest on Uncertain Tax Positions

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting principle for classification of interest on uncertain tax positions. PHI, Pepco, DPL and ACE have reclassified interest on uncertain tax positions as interest expense from income tax expense in the Consolidated Statements of Operations and Comprehensive Income. GAAP does not address the preferability of one acceptable method of accounting over the other for the classification of interest on uncertain tax positions. However, PHI, Pepco, DPL, and ACE believe this change is preferable for comparability of their financial statements with the financial statements of the other Registrants in the combined filing, for consistency with FERC classification, and for a more appropriate representation of the effective tax rate as they manage the settlement of uncertain tax positions and interest expense separately. PHI, Pepco, DPL, and ACE applied the change retrospectively. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the nine months ended September 30, 2015 is $1 million for PHI and less than $1 million for Pepco, DPL and ACE. The reclassification amount is more significant for the year ended December 31, 2015.

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

The accompanying consolidated financial statements as of September 30, 2016 and 2015 and for the three and nine months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2015 Consolidated Balance Sheets were obtained 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, 2016. 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 Pronouncements (All Registrants)

Exelon has identified the following new accounting standards that have been recently adopted.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share

In May 2015, the FASB issued authoritative guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the Balance Sheet. The guidance also simplified the disclosure requirements for investments valued using the practical expedient. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. The Registrants adopted the standard in the first quarter of 2016, and applied the guidance retrospectively to all prior periods presented. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income and Consolidated Statements of Cash Flows. See Note 8 Fair Value of Financial Assets and Liabilities for the disclosure impacts.

Customer s Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued authoritative guidance that clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either operate the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract. The Registrants prospectively adopted the standard in the first quarter of 2016. The adoption of this guidance had no impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Amendments to the Consolidation Analysis

In February 2015, the FASB issued authoritative guidance that amends the consolidation analysis for variable interest entities (VIEs) as well as voting interest entities. The new guidance primarily (1) changes the VIE assessment of limited partnerships, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by a reporting entity s related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity, and (5) provides a scope exception for registered and similar unregistered money market funds. The guidance became effective for the Registrants January 1, 2016. The Registrants adopted the standard in the first quarter of 2016. The Registrants have evaluated the standard and have not identified any changes to consolidation conclusions as a result of the new guidance, but have identified additional entities that are now considered VIEs. See Note 3 Variable Interest Entities for the disclosure impacts.

The following issued accounting standards are not yet required to be reflected in the consolidated financial statements of the Registrants.

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. 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. 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 are currently assessing 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 as well as the transition method that they will use to adopt the guidance. Exelon is considering the impacts of the new guidance on its ability to recognize revenue for certain contracts where collectability is in question, its accounting for contributions in aid of construction, bundled sales contracts and contracts with pricing provisions that may require it to recognize revenue at prices other than the contract price (e.g., straight line or estimated future market prices). In addition, the Registrants will be required to capitalize costs to acquire new contracts, whereas Exelon currently expenses those costs as incurred. The guidance 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. The Registrants do not plan to early adopt the standard. In March 2016, the FASB issued a final amendment to clarify the implementation guidance for principal versus agent considerations and in April 2016 issued a final amendment to clarify the guidance related to identifying performance obligations and the accounting for licenses of intellectual property. The Registrants do not expect significant impacts based on these updates. In May 2016, the FASB issued a final amendment regarding narrow scope improvements and practical expedients. The Registrants are currently assessing the impact of this update.

Leases

In February 2016, the FASB issued authoritative guidance to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing 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 for fiscal years beginning after December 15, 2018 with early adoption permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Registrants are currently assessing 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 as well as the potential to early adopt the guidance.

Intra-Entity Transfers of Assets Other Than Inventory

In October 2016, the FASB issued authoritative guidance which instructs entities to recognize the income tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs (compared to current GAAP which prohibits the recognition of current and deferred income taxes for an intra-entity asset transfer until the asset has been sold to an outside party). The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis through a cumulative-effect adjustment directly to retained earnings as of the beginning of the period of adoption. The Registrants are currently assessing 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 as well as the potential to early adopt the guidance.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued authoritative guidance intended to add or clarify guidance on the classification of certain cash receipts and payments on the statement of cash flows. The new guidance addresses cash flows related to the following: 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 standard is effective January 1, 2018, with early adoption permitted. The guidance must be applied on a retrospective basis. The Registrants are currently assessing the impacts this guidance may have on their Consolidated Statements of Cash Flows.

Impairment of Financial Instruments

In June 2016, the FASB issued authoritative guidance that adds an impairment model to U.S. GAAP called the Current Expected Credit Loss (CECL) model for financial instruments within the scope of the guidance, which includes loans, trade receivables, debt securities classified as held-to-maturity and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity would be 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. An entity must consider all available relevant information when estimating expected credit losses. Historical charge-off rates may be used as a starting point for determining expected credit losses; however, the entity must also evaluate how conditions that existed during the historical charge-off period may differ from its current expectations and accordingly revise its estimate of expected credit losses. 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. The Registrants are currently assessing 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.

Improvements to Employee Share-Based Payment Accounting

In March 2016, the FASB issued authoritative guidance intended to simplify various aspects to how share-based payment awards to employees are accounted for and presented in the financial statements. The new guidance eliminates additional paid-in capital pools and requires excess tax benefits and tax deficiencies to be recorded in the Statement of Operations and Comprehensive Income. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted if all provisions are adopted within the same period. The guidance is required to be applied on either a prospective, modified retrospective, or retrospective basis depending on the provisions applied. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

Simplifying the Transition to the Equity Method of Accounting

In March 2016, the FASB issued authoritative guidance eliminating the requirement to retroactively adopt the equity method of accounting as a result of an increase in the level ownership or degree of influence of an

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

existing investment. The guidance now requires an investor to add the cost of acquiring the additional interest in the investee to the current basis of the investor s previously held interest and adopt the equity method of accounting as of the date the investment becomes qualified for the equity method of accounting. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships

In March 2016, the FASB issued authoritative guidance which clarifies that a change in the counterparty of a derivative contract does not, in and of itself, require dedesignation of that hedge accounting relationship as long as all of the other hedge accounting criteria are met. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted. Entities have the option to adopt this standard on a prospective basis to new derivative contract novations or on a modified retrospective basis. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the transition method and the potential to early adopt the guidance.

Contingent Put and Call Options in Debt Instruments

In March 2016, the FASB issued authoritative guidance which simplifies the embedded derivative analysis for debt instruments containing contingent call or put options by removing the requirement to assess whether a contingent event is related to interest rates or credit risks. The guidance clarifies that a contingent put or call option embedded in a debt instrument would be evaluated for possible separate accounting as a derivative instrument without regard to the nature of the exercise contingency. The standard is effective for fiscal years beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied on a modified retrospective basis to all existing and future debt instruments. The Registrants do not expect that this guidance will have a significant impact on Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures and are currently assessing the potential to early adopt the guidance.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued authoritative guidance which (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 for fiscal years beginning after December 15, 2017 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). The Registrants are currently assessing 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 as well as the potential to early adopt the guidance.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Simplifying the Measurement of Inventory

In July 2015, the FASB issued authoritative guidance that requires inventory to be measured at the lower of cost or net realizable value. The new guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. The guidance is effective for periods beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied prospectively. The Registrants do not expect that this guidance will have a significant impact on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The Registrants are currently assessing the potential to early adopt the guidance.

3. Variable Interest Entities (All Registrants)

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

At September 30, 2016, Exelon, Generation, BGE, PHI and ACE collectively consolidated nine VIEs or VIE groups for which the applicable Registrant was the primary beneficiary. At December 31, 2015, Exelon, Generation and BGE collectively had seven consolidated VIEs or VIE groups and PHI and ACE collectively had one consolidated VIE (*see Consolidated Variable Interest Entities below).* As of September 30, 2016 and December 31, 2015, Exelon and Generation collectively had significant interests in nine and eight other VIEs, respectively, for which the applicable Registrant does not have the power to direct the entities activities and, accordingly, was not the primary beneficiary *(see Unconsolidated Variable Interest Entities below).*

Consolidated Variable Interest Entities

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 another distributed energy company. 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 will contribute up to a total of $250 million of equity incrementally from inception through December 2016 in proportion to their ownership interests, which equates up to approximately $172 million for the tax equity investor and up to $78 million for Generation (see Note 18 Commitments and Contingencies for more details). The investment in the distributed energy company was evaluated, and it was determined to be a VIE for which Generation is not the primary beneficiary (see additional details in the Unconsolidated Variable Interest Entities section below). As of December 31, 2015, Generation consolidated 2015 ESA Investco, LLC under the voting interest model. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, 2015 ESA Investco, LLC meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner. (For additional details related to the new consolidation guidance, see Note 2 New Accounting Pronouncements.) Under VIE guidance, Generation is the primary beneficiary; therefore, the entity continues to be consolidated.

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

A retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

- 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,
- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property, 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 September 30, 2016 and December 31, 2015, ComEd, PECO, Pepco and DPL did not have any material consolidated VIEs.

As of September 30, 2016 and December 31, 2015, Exelon, Generation, BGE, 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.
- Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 26 Related Party Transactions of the Exelon 2015 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 have been suspended during the term of the Reliability Support Services Agreement (RSSA) (see Note 5 Regulatory Matters for additional details),

Generation provided a $400 million loan to CENG. As of September 30, 2016, the remaining obligation is $312 million, including accrued interest, which reflects the principal payment made in January 2015,

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 18 Commitments and Contingencies for more details),

in connection with CENG s severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2014 through 2016. As of September 30, 2016, there was no remaining obligation,

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 18 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.

Generation provides approximately $16 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy.

Generation provides a $75 million parental guarantee to a third-party gas supplier and provides limited recourse to other third-party gas suppliers and customers in support of its retail gas group.

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.

In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three and nine months ended September 30, 2016, BGE remitted $27 million and $64 million to BondCo, respectively. During the three and nine months ended September 30, 2015, BGE remitted $21 million and $63 million to BondCo, respectively.

In the case of ATF, proceeds from the sale of each series of transition bonds by ATF were transferred to ACE in exchange for the transfer by ACE to ATF of the right to collect a non-bypassable Transition Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three and nine months ended September 30, 2016, ACE transferred $20 million and $47 million to ATF, respectively. During the three and nine months ended September 30, 2015, ACE transferred $18 million and $45 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;

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Exelon, Generation, BGE, PHI and ACE did not provide any additional material financial support to the VIEs;

Exelon, Generation, BGE, 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, BGE s, PHI s or ACE s general credit.

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at September 30, 2016 and December 31, 2015 are as follows:

	September 30, 2016					December 31, 2015				
				Successor					*Predecessor*	
	Exelon[a][b]	Generation	BGE	PHI[b]	ACE	Exelon[a]	Generation	BGE	PHI	ACE
Current assets	$ 914	$ 849	$ 44	$ 20	$ 15	$ 909	$ 881	$ 23	$ 12	$ 12
Noncurrent assets	8,235	8,201	3	31	19	8,009	8,004	3	18	18
Total assets	$ 9,149	$ 9,050	$ 47	$ 51	$ 34	$ 8,918	$ 8,885	$ 26	$ 30	$ 30
Current liabilities	$ 569	$ 439	$ 84	45	$ 40	$ 473	$ 387	$ 81	$ 48	$ 48
Noncurrent liabilities	3,090	2,979		111	99	2,927	2,884	41	124	124
Total liabilities	$ 3,659	$ 3,418	$ 84	$ 156	$ 139	$ 3,400	$ 3,271	$ 122	$ 172	$ 172

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of September 30, 2016 and December 31, 2015, these assets and liabilities primarily consisted of the following:

	September 30, 2016					December 31, 2015				
				Successor					*Predecessor*	
	Exelon[a][b]	Generation	BGE	PHI[b]	ACE	Exelon[a]	Generation	BGE	PHI	ACE
Cash and cash equivalents	$ 160	$ 160	$	$	$	$ 164	$ 164	$	$	$
Restricted cash	101	43	44	15	15	100	77	23	12	12
Accounts receivable, net										
Customer	264	264				219	219			
Other	42	42				43	43			
Mark-to-market derivatives assets	49	49				140	140			
Inventory										
Materials and supplies	192	192				181	181			
Other current assets	58	51		5		35	30			
Total current assets	866	801	44	20	15	882	854	23	12	12
Property, plant and equipment, net	5,139	5,139				5,160	5,160			
Nuclear decommissioning trust funds	2,173	2,173				2,036	2,036			
Goodwill	47	47				47	47			
Mark-to-market derivatives assets	32	32				53	53			
Other noncurrent assets	257	223	3	31	19	90	85	3	18	18
Total noncurrent assets	7,648	7,614	3	31	19	7,386	7,381	3	18	18
Total assets	$ 8,514	$ 8,415	$ 47	$ 51	$ 34	$ 8,268	$ 8,235	$ 26	$ 30	$ 30
Long-term debt due within one year	$ 191	$ 64	$ 81	$ 43	$ 38	$ 111	$ 27	$ 79	$ 46	$ 46
Accounts payable	201	201				216	216			
Accrued expenses	102	98	2	2	2	115	113	2	2	2
Mark-to-market derivative liabilities	24	24				5	5			
Unamortized energy contract liabilities	14	14				12	12			
Other current liabilities	34	34				13	13			
Total current liabilities	566	435	83	45	40	472	386	81	48	48
Long-term debt	661	550		111	99	666	623	41	124	124
Asset retirement obligations	2,070	2,070				1,999	1,999			
Pension obligation[c]	9	9				9	9			
Unamortized energy contract liabilities	26	26				39	39			

Other noncurrent liabilities	106	106				79	79			
Total noncurrent liabilities	2,872	2,761		111	99	2,792	2,749	41	124	124
Total liabilities	$ 3,438	$ 3,196	$ 83	$ 156	$ 139	$ 3,264	$ 3,135	$ 122	$ 172	$ 172

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the ACE 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 balance sheet. See Note 13 Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon s and Generation s Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon s and Generation s Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent 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 energy development companies, distributed energy companies, and energy generating facilities for which Generation has concluded that consolidation is not required.

As of September 30, 2016 and December 31, 2015, Exelon and Generation had significant unconsolidated variable interests in nine and eight VIEs, respectively for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $20 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 $20 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 July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation s total equity commitment in this arrangement was $91 million and was paid incrementally over an approximate two year period (see Note 18 Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and was recorded as an equity method investment. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, the distributed energy company meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick out rights of the general partner. (For additional details related to the new consolidation guidance, see Note 2 New Accounting Pronouncements.) Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method.

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,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

which is an unconsolidated VIE. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible promissory note. 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 will contribute up to a total of $250 million of equity incrementally from inception through December 2016 in proportion of their ownership interests, which equates up to approximately $172 million for the tax equity investor and up to $78 million for Generation (see Note 18 Commitments and Contingencies for additional details). Generation and the tax equity investor provide 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, which is an unconsolidated VIE. The investment in the distributed energy company was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. See additional details in the Consolidated Variable Interest Entities section above.

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

September 30, 2016	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 586	$ 531	$ 1,117
Total liabilities[a]	181	308	489
Exelon s ownership interest in VIE[a]		193	193
Other ownership interests in VIE[a]	405	34	439
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		225	225
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning[b]	11		11

December 31, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 263	$ 164	$ 427
Total liabilities[a]	22	125	147
Exelon s ownership interest in VIE[a]		11	11
Other ownership interests in VIE[a]	241	28	269
Registrants maximum exposure to loss:			
Carrying amount of equity method investments		21	21
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning[b]	17		17

(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 $135 million and $206 million as of September 30, 2016 and December 31, 2015, respectively; offset by payables to ZionSolutions LLC of $124 million and $189 million as of September 30, 2016 and December 31, 2015, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For each of the unconsolidated VIEs, Exelon and Generation has 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)

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. In the first quarter of 2016, Exelon estimated and recorded total nominal cost commitments of $508 million, excluding renewable generation commitments (approximately $444 million on a net present value basis, excluding renewable generation commitments and charitable contributions).

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware and New Jersey and continued negotiations in Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in total nominal cost of commitments of $513 million, excluding renewable generation commitments (with no change in the $444 million net present value basis amount, excluding renewable generation commitments and charitable contributions). A similar filing will be required in Maryland. These filings, which reflect agreements reached with certain parties to the merger proceedings in the jurisdictions, are subject to regulatory review and approval in each jurisdiction. The Delaware Commission approved the amounts and allocations in September and October 2016 and an order from the New Jersey BPU is expected in the fourth quarter of 2016. No changes in commitment cost levels are required in the District of Columbia.

The proposed settlements included certain changes in the amount and mix of previously reported, expected commitment types, resulting in adjustments to the estimated commitment costs recorded by Exelon Corporate and by the individual PHI utility reporting entities such that more commitments are expected to be obligations of Exelon Corporate for energy efficiency, workforce development and other programs as opposed to obligations of PHI, Pepco, DPL and ACE for additional customer rate credits. Specifically, for the three months ended September 30, 2016, Exelon Corporate recorded an increase of $55 million and PHI, Pepco, DPL and ACE recorded decreases of $50 million, $13 million, $27 million and $10 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 were recognized as total commitment costs in Operating and maintenance expense in Exelon s, PHI s, Pepco s, DPL s and ACE s Consolidated Statements of Operations and Comprehensive Income for the nine months ended September 30, 2016 and PHI s successor period:

					Successor	
Description	**Expected Payment Period**	**Pepco[(a)]**	**DPL[(a)]**	**ACE[(a)]**	**PHI[(a)]**	**Exelon[(a)]**
Rate credits	2016 2017	$ 91	$ 58	$ 101	$ 250	$ 250
Energy efficiency	2016 2021					120
Charitable contributions	2016 2026	28	12	10	50	50
Delivery system modernization	Q2 2016					22
Green sustainability fund	Q2 2016					14
Workforce development	2016 2020					24
Other		7	7		14	33
Total		$ 126	$ 77	$ 111	$ 314	$ 513

(a) Included within the individual line items is the most favored nation provision estimate of $6 million, $5 million $38 million, $49 million, and $134 million at Pepco, DPL, ACE, PHI and Exelon, respectively.

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. The actual cost of investment in new generation may differ depending on the result of final negotiations and application of the most favored nation provision. 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.

Exelon was previously named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the merger transaction, and that Exelon aided and abetted the individual directors breaches. The suits sought rescission of the merger and unspecified damages and costs. On June 1, 2016, the parties executed a settlement to resolve all claims, subject to the approval of the Delaware Court. A hearing had been scheduled for September 8, 2016 in the Delaware Court to consider whether to approve the settlement. However, on August 19, 2016, the plaintiffs advised Exelon that they had determined to dismiss the case in its entirety and with prejudice. On August 24, 2016, the Delaware Court issued an order approving the dismissal.

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 and in July and August, Exelon, PHI, the MDPSC, Prince George s County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the

Circuit Court

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 a notice of appeal. Exelon believes the matters are without merit. These appeals are not expected to be resolved any earlier than the first quarter of 2017.

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 September 9, 2016, the Court consolidated the appeals. Although the Court has not yet issued a scheduling order, a decision on this matter is not expected until the second or third quarter of 2017. Exelon believes the matters are without merit.

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[(a)]	180
Cash paid for PHI stock-based compensation equity awards[(b)]	29
Total purchase price	$ 7,142

(a) As of December 31, 2015, the preferred stock was included in Other non-current assets on Exelon s Consolidated Balance Sheets.

(b) 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 valuations performed in the first quarter of 2016 to assess the fair value of certain assets acquired and liabilities assumed were considered preliminary as a result of the short time period between the closing of the merger and the end of the first quarter of 2016. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair value of assets acquired and liabilities assumed; however, Exelon expects to finalize these amounts by the end of 2016. During the second and third quarters, certain modifications were made to preliminary valuation amounts for acquired property, plant and equipment, unamortized energy contracts, current liabilities, long-term debt,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

deferred income taxes and pension and OPEB liability resulting in a $16 million net decrease to goodwill. The preliminary amounts recognized are subject to further revision to the extent that additional information is obtained about the facts and circumstances that existed as of the acquisition date. Any changes to the fair value assessments may affect the purchase price allocation and could potentially impact goodwill.

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:

Preliminary Purchase Price Allocation	
Current assets	$ 1,441
Property, plant and equipment	11,088
Regulatory assets	5,015
Other assets	248
Goodwill	4,000
Total assets	$ 21,792
Current liabilities	$ 2,752
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,442
Pension and OPEB liability	821
Other liabilities	187
Total liabilities	$ 14,650
Total purchase price	$ 7,142

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Exelon s and PHI s carrying amount of goodwill for the nine months ended September 30, 2016 was as follows:

	PHI	Exelon[(a)]
Beginning balance, December 31, 2015	$	$ 2,672
Goodwill from business combination	4,016	4,016
Measurement period adjustments	(16)	(16)
Ending balance, September 30, 2016	$ 4,000	$ 6,672

(a) As of September 30, 2016, there were no changes to the carrying amount of goodwill for ComEd, see Note 11 Intangible Assets of the Exelon 2015 Form 10-K for further information.

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 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 September 30, 2016. 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 Operating revenues of $1.4 billion and Net income of $169 million during the three months ended September 30, 2016, and Operating revenues of $2.7 billion and Net loss of $(92) million during the nine months ended September 30, 2016.

For the three and nine months ended September 30, 2016 and 2015, the Registrants have recognized costs to achieve the PHI acquisition as follows:

Acquisition, Integration and Financing Costs[a]	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon[b]	$ 20	$ 22	$ 123	$ 84
Generation	9	10	29	30
ComEd[c]		3	(6)	9
PECO	1	1	3	4
BGE[c]	1	2	(3)	4
Pepco[c]	3	1	26	3
DPL[c]	2		18	2
ACE	2		17	1

Acquisition, Integration and Financing Costs[a]	*Successor* Three Months Ended September 30, 2016	*Predecessor* Three Months Ended September 30, 2015	*Successor* March 24 to September 30, 2016	*Predecessor* January 1 to March 23, 2016	*Predecessor* Nine Months Ended September 30, 2015
PHI[c]	$ 7	$ 3	$ 63	$ 29	$ 16

(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 nine months ended September 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $10 million, $3 million and $13 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, 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 September 30,		Nine Months Ended September 30,		Year Ended December 31,
	2016[a]	2015[b]	2016[a]	2015[b]	2015[c]
Total operating revenues	$ 9,002	$ 8,545	$ 24,468	$ 26,129	$ 33,823
Net income attributable to common shareholders	501	746	1,346	2,169	2,618
Basic earnings per share	$ 0.54	$ 0.81	$ 1.46	$ 2.36	$ 2.85
Diluted earnings per share	0.54	0.81	1.45	2.35	2.84

(a) The amounts above include adjustments for non-recurring costs directly related to the merger of $20 million and $660 million for the three and nine months ended September 30, 2016, respectively, and intercompany revenue of $171 million for the nine months ended September 30, 2016.

(b) The amounts above include adjustments for non-recurring costs directly related to the merger of $25 million and $100 million and intercompany revenue of $192 million and $426 million for the three and nine months ended September 30, 2015, respectively.

(c) The amounts above include adjustments for non-recurring costs directly related to the merger of $92 million and intercompany revenue of $559 million for the year ended December 31, 2015.

Acquisition of ConEdison Solutions (Exelon and Generation)

On September 1, 2016, Generation acquired the competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc. (ConEdison Solutions), a subsidiary of Consolidated Edison, Inc. for a purchase price of $257 million including net working capital of $204 million. The renewable energy, sustainable services and energy efficiency businesses of ConEdison Solutions are excluded from the transaction. As of September 30, 2016, Generation had remitted $235 million to ConEdison Solutions and the remaining balance of $22 million, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets, will be paid during the first quarter of 2017.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the ConEdison Solutions acquisition by Generation as of September 1, 2016:

Total consideration transferred	$ 257
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 204
Property, plant and equipment	2
Mark-to-market derivative assets	6
Unamortized energy contract assets	100
Customer relationships	9
Other assets	1
Total assets	$ 322
Mark-to-market derivative liabilities	$ (65)

Total liabilities	$ (65)
Total net identifiable assets, at fair value	$ 257

The purchase price equaled the estimated fair value of the net assets acquired and the liabilities assumed and, therefore, no goodwill or bargain purchase was recorded as of September 30, 2016. The purchase accounting is preliminary, and, although not expected, may be further adjusted from what is shown above. Accounting guidance provides that the allocation of the purchase price may be modified up to one year from the date of the acquisition as more information is obtained about the fair value of assets acquired and liabilities assumed; however, Generation expects to finalize these amounts by the first quarter of 2017.

The fair values of ConEdison Solutions 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.

It is impracticable to determine the post-close impact of ConEdison Solutions as the operations of ConEdison Solutions have been integrated into Generation s operations and are therefore not distinguishable after the acquisition.

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

On August 8, 2016, Generation executed a series of agreements with Entergy Nuclear FitzPatrick LLC (Entergy) to acquire the 838MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York for a cash purchase price of $110 million. As part of the transaction, Generation would receive the FitzPatrick NDT fund assets and assume the obligation to decommission FitzPatrick. Closing of the transaction is currently anticipated to occur in the second quarter of 2017 and is dependent upon regulatory approval by FERC, NRC and the New York Public Service Commission (NYPSC). The transaction is also subject to the notification and reporting requirements of the HSR Act (which has been completed) and other customary closing conditions. The NRC license for FitzPatrick expires in 2034. Entergy had previously announced plans in November 2015 to early retire FitzPatrick at the end of the current fuel cycle in January 2017. Under the terms of the agreements, Generation will reimburse Entergy for approximately $200 million to $250 million of incremental costs to prepare for and conduct the plant refueling outage as well as to operate and maintain the plant after the refueling outage, scheduled to end in February 2017, through the closing date. These are costs which otherwise would have been avoided by FitzPatrick s planned permanent shutdown in January 2017. Generation will be entitled to all revenues from FitzPatrick s electricity and capacity sales for the period commencing upon completion of the refueling outage through the acquisition closing date. The agreements provide for certain termination rights, including the right of either party to terminate if the transaction has not been consummated within 12 months due to failure to obtain the required regulatory approvals.

On October 11, 2016, Public Citizen, Inc. filed a protest with FERC challenging Generation and Entergy s application to FERC for the transfer of ownership of FitzPatrick. No other party to the proceeding has filed any protests or comments. Generation and Entergy had requested FERC to approve the FitzPatrick transaction by November 18, 2016, however FERC is under no obligation to do so. The timing of FERC s decision on Generation and Entergy s application and the outcome of this protest are currently uncertain. Refer to Note 5 Regulatory Matters for additional information on the New York CES and ZEC program.

The transaction is expected to be accounted for as a business combination. For accounting and financial reporting purposes, the costs for which Generation reimburses Entergy as well as the revenue received from FitzPatrick prior to the closing of the transaction will be treated as part of the purchase price consideration. Generation will record the fair value of the assets acquired and liabilities assumed as of the acquisition date. To the extent the purchase price is greater than the fair value of the net assets acquired, goodwill will be recorded. To the extent the fair value of the net assets acquired is greater than the purchase price, a bargain purchase gain will be recorded.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of September 30, 2016, Generation has paid a non-refundable deposit of $10 million and reimbursed Entergy for $9 million in costs all of which have been classified with Other noncurrent assets on Exelon s and Generation s Consolidated Balance Sheets. These amounts are also reflected within Acquisition of businesses on Exelon s and Generation s Consolidated Statements of Cash Flows.

Asset Divestitures (Exelon, Generation, PHI and Pepco)

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.

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. See Note 10 Debt and Credit Agreements for more information. As of September 30, 2016, $46 million of Property, plant and equipment and $5 million of Asset retirement obligation are classified as held for sale within Other current assets and Other current liabilities, respectively, on Exelon s and Generation s Consolidated Balance Sheets. In October 2016, Generation entered into an agreement to sell a portion of the Upstream assets which is expected to close before December 31, 2016.

In July 2016, DPL completed the sale of a 9 acre land parcel located on South Madison Street in Wilmington, DE, resulting in a pre-tax gain of approximately $4 million. 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 2015 Form 10-K and Note 7 Regulatory Matters of the PHI 2015 Form 10-K appropriately represent, 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, 2016, 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 2017 after the ICC s review and approval, which is due by December 2016. The revenue requirement requested is based on 2015 actual costs plus projected 2016 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2015 to the actual costs incurred that year. ComEd s 2016 filing request includes a total increase to the revenue requirement of $138 million, reflecting an increase of $139 million for the initial revenue requirement for 2017 and a decrease of $1 million related to the annual reconciliation for 2015. The revenue requirement for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.71% inclusive of an allowed ROE of 8.64%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2015 provided for a weighted average debt and equity return on distribution rate base of 6.69% inclusive of an allowed ROE of 8.59%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 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 2015 Form 10-K.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Grand Prairie Gateway Transmission Line (Exelon and ComEd). On December 2, 2013, ComEd filed a request to obtain the ICC s approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On October 22, 2014, the ICC issued an Order approving ComEd s request. The City of Elgin and certain other parties each filed an appeal of the ICC Order in the Illinois Appellate Court for the Second District. ComEd then reached a settlement of the appeal filed by all parties except Elgin. On March 31, 2016, the Illinois Appellate Court issued its opinion affirming the ICC s grant of a certificate to ComEd to construct and operate the line. Elgin did not seek further review of the Illinois Appellate Court decision. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd s request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd s transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd s control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd s transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. ComEd has acquired the necessary land rights across the project route through voluntary transactions. ComEd began construction of the line during 2015 with an expected in-service date of 2017.

FutureGen Industrial Alliance, Inc (Exelon and ComEd). During 2013, the ICC approved, and directed ComEd and Ameren (the Utilities) to enter into 20-year sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The order also directs ComEd and Ameren to recover these costs from their electric distribution customers through the use of a tariff, regardless of whether they purchase electricity from ComEd or Ameren, or from competitive electric generation suppliers.

In February 2013, ComEd filed an appeal with the Illinois Appellate Court questioning the legality of requiring ComEd to procure power for retail customers purchasing electricity from competitive electric generation suppliers. On July 22, 2014, the Illinois Appellate Court issued its ruling re-affirming the ICC s order requiring ComEd to enter into the sourcing agreement with FutureGen and allowing the use of a tariff to recover its costs. ComEd decided not to appeal the Illinois Appellate Court s decision to the Illinois Supreme Court. However, the competitive electric generation suppliers and several large consumers petitioned for leave to appeal the Illinois Appellate Court s decision. On November 26, 2014, the Illinois Supreme Court granted the petition. ComEd executed the sourcing agreement with FutureGen in accordance with the ICC s order. In addition, ComEd filed a petition with the ICC seeking approval of the tariff allowing for the recovery of its costs associated with the FutureGen contract from all of its electric distribution customers, which was approved by the ICC on September 30, 2014.

In February 2015, the DOE suspended funding for the cost development of FutureGen. On January 13, 2016, FutureGen informed the Illinois Supreme Court that it had ceased all development efforts on the FutureGen project. Accordingly, FutureGen requested that the court dismiss the proceeding as moot. In February 2016, FutureGen terminated its sourcing agreement with ComEd. On May 19, 2016, the Illinois Supreme Court dismissed the matter as moot. As a result, ComEd is under no further obligation under this agreement.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). Through PECO s first two PAPUC approved DSP Programs, PECO procured electric supply for its default electric customers through PAPUC approved competitive procurements. DSP I and DSP II expired on May 31, 2013 and May 31, 2015, respectively.

The second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

allow its low-income CAP customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By an Order entered on January 24, 2014, the PAPUC approved PECO s plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court (Court), claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. The PAPUC, as well as the low-income advocates and the Office of Consumer Advocate, appealed the Court s decision. On April 5, 2016, the Pennsylvania Supreme Court declined to accept the appeals. On May 11, 2016, the PAPUC issued a Secretarial Letter requiring PECO to propose a rule revision to the PECO CAP Shopping Plan consistent with the Court s decision. On July 19, 2016, PECO filed a letter stating its intent to revise its Plan by September 1, 2016 to incorporate the rule revision. On September 1, 2016, PECO filed its proposed rule revision that is consistent with the Court s opinion with a proposed effective date of April 14, 2017.

On December 4, 2014, the PAPUC approved PECO s third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO procured electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. Beginning in June 2016, the medium commercial class (101-500 kW) moved to spot market pricing. In September 2016, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the final of its four scheduled procurements. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Consolidated Statement of Operations and Comprehensive Income.

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 October 4, 2016, the Administrative Law Judge recommended that PECO s previously filed partial settlement be approved without modification. The settlement would extend the program period through May 2021 and consolidate the Medium Commercial and Large Commercial classes of default service customers into a Consolidated Large Commercial Class proposed by the Company. The issue of PECO s implementation of CAP Shopping was reserved for briefing, and the Administrative Law Judge determined that issue was not a part of the DSP IV case. A decision by the PAPUC is expected in December 2016.

For further information on the Pennsylvania procurement proceedings, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

Energy Efficiency Programs (Exelon and PECO). On June 19, 2015, the PAPUC issued its Phase III EE&C implementation order that provides energy consumption reduction requirements for the third phase of Act 129 s EE&C program with a five-year term from June 1, 2016 through May 31, 2021.

Pursuant to the Phase III implementation order, PECO filed its five-year EE&C Phase III Plan with the PAPUC on November 30, 2015. The Plan sets forth how PECO will reduce electric consumption by at least 1,962,659 MWh, with a goal of 2,100,875 MWh in its service territory for the period June 1, 2016 through May 31, 2021. The PAPUC approved PECO s EE&C Phase III Plan, with requested clarifications, on May 19, 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For further information on energy efficiency programs, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

Maryland Regulatory Matters

2016 Maryland Electric Distribution Rate Case (Exelon, PHI and Pepco). On April 19, 2016, Pepco filed an application with the MDPSC requesting an increase of $127 million to its electric distribution base rates, which was later updated to $103 million, based on a requested ROE of 10.6%. The application is inclusive of a request seeking recovery of Pepco s regulatory assets associated with its AMI program over a five-year period supported by evidence demonstrating that the benefits of the AMI program exceed the costs on a present value basis. Any adjustments to rates approved by the MDPSC are expected to take effect in November 2016. In addition to the proposed rate increase, Pepco is proposing to continue its Grid Resiliency Program initially approved in July 2013 in connection with Pepco s electric distribution rate case filed in November 2012. Under the Grid Resiliency Program, Pepco is authorized to receive recovery of specific investments as the assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, Pepco proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing $16 million a year for two years for a total of $32 million. Pepco cannot predict how much of the requested rate increase the MDPSC will approve or if it will approve a continuation of Pepco s Grid Resiliency Program proposal.

2016 Maryland Electric Distribution Base Rates (Exelon, PHI and DPL). On July 20, 2016, DPL filed an application with the MDPSC requesting an increase of $66 million to its electric distribution base rates, which was later updated to $57 million, based on a requested ROE of 10.6%. The application is inclusive of a request seeking recovery of DPL s regulatory assets associated with its AMI program over a five-year period supported by evidence demonstrating that the benefits of the AMI program exceed the costs on a present value basis. Any adjustments to rates approved by the MDPSC are expected to take effect in February 2017. DPL cannot predict how much of the requested increase the MDPSC will approve. In addition to the proposed rate increase, DPL is proposing to continue its Grid Resiliency Program initially approved in September 2013 in connection with DPL s electric distribution rate case filed in February 2013. Under the Grid Resiliency Program, DPL is authorized to receive recovery of specific investments as the assets are placed in service through the Grid Resiliency Charge. In connection with the Grid Resiliency Program, DPL proposes to accelerate improvement to priority feeders and install single-phase reclosing fuse technology by investing $4.6 million a year for two years for a total of $9.2 million. DPL cannot predict whether the MDPSC will approve a continuation of DPL s Grid Resiliency Program proposal.

2015 Maryland Electric and Natural Gas Distribution Rate Case (Exelon and BGE). On November 6, 2015, and as amended through the course of the proceeding, BGE filed for electric and natural gas base rate increases with the MDPSC, ultimately requesting annual increases of $116 million and $78 million respectively, of which $104 million and $37 million, were related to recovery of electric and natural gas smart grid initiative costs, respectively. BGE also proposed to recover an annual increase of approximately $30 million for Baltimore City underground conduit fees through a surcharge.

On June 3, 2016, the MDPSC issued an order in which the MDPSC found compelling evidence to conclude that BGE s smart grid initiative overall was cost beneficial to customers. However, the June 3 order contained several cost disallowances and adjustments, including not allowing BGE to defer or recover through a surcharge the $30 million increase in annual Baltimore City underground conduit fees. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions including the decision associated with the Baltimore City underground conduit fees. OPC also subsequently filed for a petition for rehearing of the June 3 order.

On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. Through the combination of the orders, the MDPSC authorized electric and natural gas rate increases of $44 million and $48 million, respectively, and an allowed ROE for the electric and natural gas distribution businesses of 9.75% and 9.65%, respectively. The new electric and natural gas base rates took effect for service rendered on or after June 4, 2016. However, MDPSC s July 29 order on the petition on rehearing still did not allow BGE to defer or recover through a surcharge the increase in Baltimore City underground conduit fees.

On August 26, 2016, BGE filed an appeal of the MDPSC s orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC s order but with the Circuit Court for Baltimore City. BGE cannot predict the outcomes of these appeals. Refer to the Smart Meter and Smart Grid Investment disclosure below for further details on the impact of the ultimate disallowances contained in the orders to BGE.

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 September 30, 2016 and December 31, 2015, the balance of BGE s regulatory asset was $235 million and $196 million, respectively, representing incremental program deployment costs. The current quarter balance of $235 million consists of three major components, including $148 million of unamortized incremental deployment costs of the AMI program, $55 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 September 30, 2016 reflects the impact of the cost disallowances and adjustments discussed below. 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 $55 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 part of the 2015 electric and natural gas distribution rate case filed on November 6, 2015, BGE sought recovery of its smart grid initiative costs, supported by evidence demonstrating that BGE had, in fact, implemented a cost-beneficial advanced metering system. On June 3, 2016, the MDPSC issued an order concluding that the smart grid initiative overall is cost beneficial to its customers. However, the June 3 order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for non-AMI meters replaced under the program. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions and change certain of the cost disallowances and adjustments to enable BGE to defer those costs for recovery through future electric and natural gas rates. OPC also subsequently filed for a petition for rehearing of the June 3 order. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. On August 26, 2016, BGE filed an appeal of the MDPSC s orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC s order but with the Circuit Court for Baltimore City. BGE cannot predict the outcomes of these appeals.

As a combined result of the MDPSC orders, BGE recorded a $52 million charge 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. Pursuant to the combined MDPSC orders, BGE also reclassified $55 million of non-AMI plant costs from Property, plant and equipment, net to Regulatory assets on Exelon s and BGE s Consolidated Balance Sheets as of September 30, 2016. For further information, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

2013 Maryland Electric and Natural Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and natural gas base increases with the MDPSC. In addition to these requested rate increases, BGE s application also included a request for recovery of incremental capital expenditures and operating costs associated with BGE s proposed short-term reliability improvement plan (the ERI initiative) in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order authorizing BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. As of September 30, 2016, BGE has received approval of its updated surcharge filings three times for rates to be effective in 2014, 2015 and 2016.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE s 2013 electric and natural gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC s approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. On October 26, 2015, the Circuit Court for Baltimore City issued an order affirming the MDPSC decision. However, on November 23, 2015, the residential consumer advocate filed an appeal of the Circuit Court s decision with the Maryland Court of Special Appeals. On March 7, 2016, the consumer advocate withdrew its appeal and no further action is expected.

MDPSC New Generation Contract Requirement (Exelon, Generation, BGE, PHI, Pepco and DPL). On April 12, 2012, the MDPSC issued an order that requires BGE, Pepco and DPL (collectively, the Contract EDCs) to negotiate and enter into a contract with the winning bidder of a competitive bidding process to build one new power plant in the range of 650 to 700 MWs beginning in 2015, in amounts proportional to their relative SOS loads. Under the terms of the order, the winning bidder was to construct a 661 MW natural gas-fired combined cycle generation plant in Waldorf, Maryland, with an expected commercial operation date of June 1, 2015, and each of the Contract EDCs was to recover its costs associated with the contract through surcharges on its respective SOS customers.

In response to a complaint filed by a group of generating companies in the PJM region, on September 30, 2013, the U.S. District Court for the District of Maryland issued a ruling that the MDPSC s April 2012 order violated the Supremacy Clause of the U.S. Constitution by attempting to regulate wholesale prices. In contrast, on October 1, 2013, in response to appeals filed by the Contract EDCs and other parties, the Maryland Circuit Court for Baltimore City upheld the MDPSC s orders requiring the Contract EDCs to enter into the contracts.

On October 24, 2013, the Federal district court issued an order ruling that the contracts are illegal and unenforceable. In November 2013 both the winning bidder and the MDPSC appealed the Federal district court decision to the U.S. Court of Appeals for the Fourth Circuit, which affirmed the lower Federal court ruling. On November 26, 2014, both the winning bidder and the MDPSC petitioned the U.S. Supreme Court to consider hearing an appeal of the Fourth Circuit decision. On October 19, 2015, the U.S. Supreme Court agreed to review the decision. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit s ruling upholding the Federal district court s decision.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The decision of the Maryland Circuit Court was appealed to the Maryland Court of Special Appeals and was stayed pending decision by the U.S. Supreme Court. On August 1, 2016, the Contract EDCs submitted a filing requesting that the MDPSC take notice of the U.S. Supreme Court s decision, and notifying the MDPSC that the Contract EDCs will dismiss their appeal pending at the Maryland Court of Special Appeals. On September 14, 2016, the Maryland Court of Special Appeals dismissed the pending appeal and the matter is considered closed.

Delaware Regulatory Matters

2016 Electric and Natural Gas Distribution Base 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 and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allowed DPL to put into effect $2.5 million of the rate increase two months after filing the applications which were effective July 16, 2016. It also allows the entire requested rate increase seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. DPL cannot predict how much of the requested increase the DPSC will approve.

District of Columbia Regulatory Matters

2016 Electric Distribution Base 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, which was updated to $82 million on October 14, 2016, based on a requested ROE of 10.6%. The DCPSC has issued a procedural schedule indicating a final decision will be issued by July 25, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect soon thereafter. Pepco cannot predict how much of the requested increase the DCPSC will approve.

On April 18, 2016, a party to a separate DCPSC proceeding filed a motion to suspend Pepco s bill stabilization adjustment (BSA), which decouples distribution revenues from utility customers from the amount of electricity delivered. On September 9, 2016, the DCPSC denied the party s motion and determined that the appropriate forum in which to determine whether the BSA continues to be just and reasonable is in Pepco s rate case proceeding. In addition, the DCPSC stated that it was putting Pepco on notice that all funds collected for the BSA from January 2015 to the issuance of a decision in the rate case proceeding are subject to refund should the DCPSC determine that such funds were not justly or reasonably collected. On October 7, 2016, Pepco filed for reconsideration of this order and requested clarification that the order was not final and that the BSA matter would be decided in the base rate case. Pepco also argued that, if the order were considered final, the DCPSC reconsider its ruling that funds collected from the BSA can be retroactively refunded. Pepco cannot predict the outcome of this matter or the impact of a refund if ordered by the DCPSC.

District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco). In May 2014, the Council of the District of Columbia enacted the Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act), which provided enabling legislation for the District of Columbia Power Line Undergrounding (DC PLUG) initiative which would selectively place underground some of the District of Columbia s most outage-prone power lines.

The Improvement Financing Act provides that: (i) Pepco is to fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a volumetric surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost is to be financed by the District of Columbia s issuance of securitized bonds, which bonds will be repaid through a volumetric surcharge (the DDOT surcharge) on the electric bills of Pepco District of Columbia customers that Pepco will remit to the District of Columbia; and (iii) the remaining costs up to $125 million are to be covered by

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount.

In June 2014, Pepco and DDOT filed a Triennial Plan related to the construction of selected underground feeders in the District of Columbia. In August 2014, Pepco filed an application for the issuance of a financing order to provide for the issuance of the District s bonds. In March 2016, the DCPSC s orders approving the Triennial Plan and the application for financing were upheld upon the resolution of appeals that had been filed with the District of Columbia Court of Appeals. In compliance with the Improvement Financing Act, on September 30, 2016, Pepco and DDOT filed a Second Triennial Plan. Recognizing the delays to the First Triennial Plan, Pepco and DDOT requested that the DCPSC hold the Second Triennial Plan in abeyance.

In June 2015, an agency of the federal government served by Pepco asserted that the DDOT surcharge constitutes a tax on end users from which the federal government is immune. PHI is currently evaluating the assertion and the resolution of this matter will likely further delay implementation of the DC PLUG initiative.

New Jersey Regulatory Matters

2016 Electric Distribution Base 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, and an increase of $45 million (before New Jersey sales and use tax) to its electric distribution base rates, with the new rates effective immediately. The stipulation of settlement provided that a determination on PowerAhead would be separated into a phase II of the rate proceeding and decided at a later date and the parties would seek to resolve the matter by the end of 2016, although resolution will most likely occur in the first quarter of 2017. PowerAhead includes capital investments to advance modernization of the electric grid through energy efficiency, increased distributed generation, and resiliency, focused on improving the distribution system s ability to withstand major storm events. ACE cannot predict if the NJBPU will approve the PowerAhead initiative.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). *O*n February 1, 2016, ACE submitted its 2016 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 NUGs and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE s uncollectible accounts.

The net impact of adjusting the charges as proposed is an overall annual rate increase of $9 million (revised to $19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax. 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 Clean Energy Standard (CES), a component of which includes creation of a Tier 3 Zero Emission Credit (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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 by the federal government. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. 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 CES initially identifies the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. The program specifically provides that Nine Mile Point Units 1 & 2 qualify jointly as a single facility and if either unit permanently ceases operations then both units will no longer qualify for ZEC payments for the remainder of the program. As issued, the order provides that the duration of the program beyond the first tranche is conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018; however, Generation and CENG requested clarification, or in the alternative limited rehearing, that this condition is applicable to the FitzPatrick facility only and has no bearing on the 12-year duration of the program for Ginna or Nine Mile Point. To date, several parties have filed with the NYPSC requests for rehearing or reconsideration of the CES and 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. Generation and CENG will seek to intervene in the case and to dismiss the lawsuit. Other legal challenges remain possible and the outcomes of each of these challenges are currently uncertain. Negotiations with NYSERDA regarding contracts for the sale of ZECs from Ginna, Nine Mile Point and FitzPatrick are ongoing, and Generation expects that NYSERDA will enter into final agreements during the fourth quarter of 2016. 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 proposed 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.

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. Because all regulatory approvals for the RSSA have now been received, Generation began recognizing revenue based on the final approved pricing contained in the RSSA. Generation also recognized a one-time revenue adjustment in April 2016 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 will be removed from Generation s results as a result of the noncontrolling interests in CENG.

The RSSA approved by the regulatory authorities has a term expiring on March 31, 2017, subject to possible extension in the event that RG&E needs additional time to complete transmission upgrades to address reliability concerns. In March 2016, RG&E notified Ginna that RG&E expects to complete the transmission upgrades prior to the RSSA expiration in March 2017 and will not need Ginna as an ongoing reliability solution after that date.

The approved RSSA requires Ginna to continue operating through the RSSA term. If Ginna does not plan to retire shortly after the expiration of the RSSA, Ginna is required to file a notice to that effect with the NYPSC no

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

later than September 30, 2016. Under the terms of the RSSA, if Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments up to a maximum of $20 million to RG&E related to capital expenditures. 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 a result, Ginna has reserved the right to withdraw this notification and cease commercial operations if the ZEC program is terminated, suspended, or stayed prior to commencement of the program on April 1, 2017 or if for any reason a contract with NYSERDA in a form and substance satisfactory to Generation and CENG is not executed for Ginna, Nine Mile Point, or FitzPatrick. Negotiations with NYSERDA are ongoing and contract execution is currently targeted for completion in the fourth quarter of 2016.

There remains an increased risk that, for economic reasons, Ginna could be retired before the end of its operating license period in 2029. In the event the plant were to be retired before the current license term ends in 2029, Exelon s and Generation s results of operations could be adversely affected by the accelerated future decommissioning costs, severance costs, increased depreciation rates, and impairment charges, among other items. 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, PHI, Pepco, DPL and ACE). ComEd s, BGE s, Pepco s, DPL s and ACE s transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd, BGE, Pepco, DPL, and ACE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd s, BGE s, Pepco s, DPL s and ACE s best estimate of the revenue requirement expected to be filed with the FERC for that year s reconciliation. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

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

			2016		
Annual Transmission Filings[a]	**ComEd**	**BGE**	**Pepco**	**DPL**	**ACE**
Initial revenue requirement increase	$ 90	$ 12	$ 2	$ 8	$ 8
Annual reconciliation (decrease) increase	4	3	(10)	(10)	(14)
Dedicated facilities (decrease) increase[b]		13			
MAPP abandonment recovery decrease[c]			(15)	(12)	
Total revenue requirement increase (decrease)	$ 94	$ 28	$ (23)	$ (14)	$ (6)
Allowed return on rate base[d]	8.47%	8.09%	7.88%	7.21%	7.83%
Previously authorized allowed return on rate base[d]	8.61%	8.46%	8.36%	7.80%	8.51%
Allowed ROE[e]	11.50%	10.50%	10.50%	10.50%	10.50%

(a) All rates are effective June 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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) In 2012, PJM terminated the MAPP transmission line construction project planned for the Pepco and DPL service territories. Pursuant to a FERC approved settlement agreement, the abandonment costs associated with MAPP were being recovered in transmission rates over a three-year period that ended in May 2016.
(d) Refers to the weighted average debt and equity return on transmission rate bases.
(e) As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

For additional information regarding ComEd and BGE s transmission formula rate filings see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K. For additional information regarding Pepco, DPL and ACE s transmission formula rate filings see Note 7 Regulatory Matters of the PHI 2015 Form 10-K.

PJM Transmission Rate Design and Operating Agreements (Exelon, Generation, ComEd, PECO, BGE, 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 an Offer of Settlement with FERC. Each state that is a party in this proceeding either signed, or will not oppose, the settlement. On July 5, 2016, a number of merchant transmission owners and load servicing entities opposed the Settlement in whole or in part. As of September 30, 2016, the Settlement is awaiting FERC s action. If the Settlement is approved, effective January 1, 2016, for the costs of the 500 kV facilities approved by the PJM Board on or after February 1, 2013, 50% will be socialized across PJM and 50% will be allocated according to an engineering formula that calculates the flows on the transmission facilities. 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.

Operating License Renewals (Exelon and Generation). Generation has 40-year operating licenses from the NRC for each of its nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC s review.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On December 9, 2014, Generation submitted an application to the NRC to extend the current operating licenses of LaSalle Units 1 and 2 by 20 years. On October 19, 2016, the NRC approved Generation s request to extend the operating licenses of LaSalle Unit 1 and 2 by 20 years to 2042 and 2043, respectively.

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 August 7, 2015, US Fish and Wildlife Service of the US Department of the Interior (Interior) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge Interior s preliminary prescription. On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all fish passage issues between the parties. Accordingly, on April 22, 2016, Exelon withdrew its Request for a Trial-Type Hearing and Alternative Prescription. 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 September 30, 2016, $27 million of direct costs associated with the Conowingo licensing effort have been capitalized. See Note 3 Regulatory Matters of the Exelon 2015 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.

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of September 30, 2016 and December 31, 2015. For additional information on the specific regulatory assets and liabilities, refer to Note 3 Regulatory Matters of the Exelon 2015 Form 10-K and Note 7 Regulatory Matters of the PHI 2015 Form 10-K.

September 30, 2016	**Exelon**	**ComEd**	**PECO**	**BGE**	*Successor* **PHI**	**Pepco**	**DPL**	**ACE**
Regulatory assets								
Pension and other postretirement benefits[a]	$ 4,096	$	$	$	$	$	$	$
Deferred income taxes[b]	1,973	73	1,555	94	251	162	38	51
AMI programs[c]	704	160	53	235	256	171	85	
Under-recovered distribution service costs [d]	232	232						
Debt costs[e]	126	43	1	7	82	18	9	6
Fair value of long-term debt[f]	828				684			
Fair value of PHI s unamortized energy contracts[g]	1,206				1,206			
Severance	6			6				
Asset retirement obligations	108	74	22	11	1	1		
MGP remediation costs	295	267	27	1				
Under-recovered uncollectible accounts	58	58						
Renewable energy	246	244			2			2
Energy and transmission programs [h][i][j][k][l]	74	31		25	18	1	8	9
Deferred storm costs	39			1	38	14	5	19
Electric generation-related regulatory asset	13			13				
Rate stabilization deferral	25			25				
Energy efficiency and demand response programs	642		1	289	352	254	98	
Merger integration costs[m][n]	23			10	13	10	3	
Under-recovered revenue decoupling[o][p]	9				9	7	2	
COPCO acquisition adjustment	9				9		9	
Recoverable Workers compensation and long-term disability cost	30				30	30		
Vacation accrual	37		13		24		14	10
Securitized stranded costs	153				153			153
CAP arrearage	7		7					
Removal costs	448				448	119	84	246
Other	45	10	9	5	19	11	4	5
Total regulatory assets	11,432	1,192	1,688	722	3,595	798	359	501
Less: current portion	1,410	205	37	214	650	122	62	89
Total non-current regulatory assets	$ 10,022	$ 987	$ 1,651	$ 508	$ 2,945	$ 676	$ 297	$ 412

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September 30, 2016	Exelon	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Regulatory liabilities								
Other postretirement benefits	$ 85	$	$	$	$	$	$	$
Nuclear decommissioning	2,704	2,238	466					
Removal costs	1,627	1,333		151	143	20	123	
Deferred rent[q]	40				40			
Energy efficiency and demand response programs	175	135	40					
DLC program costs	8		8					
Electric distribution tax repairs	79		79					
Gas distribution tax repairs	21		21					
Energy and transmission programs[h][i][r][j][k][l]	171	72	59		40	17	11	12
Over-recovered revenue decoupling[o]	5			5				
Other	70	3	6	16	45	7	12	24
Total regulatory liabilities	4,985	3,781	679	172	268	44	146	36
Less: current portion	548	204	128	54	101	20	46	35
Total non-current regulatory liabilities	$ 4,437	$ 3,577	$ 551	$ 118	$ 167	$ 24	$ 100	$ 1

December 31, 2015	Exelon	ComEd	PECO	BGE	*Predecessor* PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits	$ 3,156	$	$	$	$ 910	$	$	$
Deferred income taxes[b]	1,616	64	1,473	79	214	137	36	41
AMI programs	399	140	63	196	267	180	87	
Under-recovered distribution service costs[d]	189	189						
Debt costs	47	46	1	8	36	19	10	7
Fair value of long-term debt[f]	162							
Severance	9			9				
Asset retirement obligations	108	67	22	19	1	1		
MGP remediation costs	286	255	30	1				
Under-recovered uncollectible accounts	52	52						
Renewable energy	247	247			6		1	5
Energy and transmission programs[h][i][r][j][k][l]	84	43	1	40	33	9	11	13
Deferred storm costs	2			2	43	19	6	18
Electric generation-related regulatory asset	20			20				
Rate stabilization deferral	87			87				
Energy efficiency and demand response programs	279		1	278	401	289	111	1
Merger integration costs	6			6				
Conservation voltage reduction	3			3				
Under-recovered revenue decoupling[o][p]	30			30	14	10	4	
COPCO acquisition adjustment							13	
Workers compensation and long-term disability costs					31	31		
Vacation accrual	6		6		23		14	9
Securitized stranded costs					202			202
CAP arrearage	7		7					

Removal costs					369	92	69	208
Other	29	10	13	3	32	14	9	8
Total regulatory assets	6,824	1,113	1,617	781	2,582	801	371	512
Less: current portion	759	218	34	267	305	140	72	98
Total non-current regulatory assets	$ 6,065	$ 895	$ 1,583	$ 514	$ 2,277	$ 661	$ 299	$ 414

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**	*Predecessor* **PHI**	**Pepco**	**DPL**	**ACE**
Regulatory liabilities								
Other postretirement benefits	$ 94	$	$	$	$	$	$	$
Nuclear decommissioning	2,577	2,172	405					
Removal costs	1,527	1,332		195	150	21	129	
Energy efficiency and demand response programs	92	52	40		1			1
DLC program costs	9		9					
Electric distribution tax repairs	95		95					
Gas distribution tax repairs	28		28					
Energy and transmission programs[(h)(i)(r)(j)(k)(l)]	131	53	60	18	27	16	19	8
Over-recovered revenue decoupling[(o)]	1			1				
Other	16	5	2	8	35	7	12	16
Total regulatory liabilities	4,570	3,614	639	222	213	44	160	25
Less: current portion	369	155	112	38	66	15	49	18
Total non-current regulatory liabilities	$ 4,201	$ 3,459	$ 527	$ 184	$ 147	$ 29	$ 111	$ 7

(a) As of September 30, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of $1,087 million established at the date 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.

(b) As of September 30, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $19 million, $32 million, $29 million, $20 million and $18 million for ComEd, BGE, Pepco, DPL and ACE, respectively. As of December 31, 2015, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $15 million, $16 million, $36 million, $18 million and $15 million for ComEd, BGE, Pepco, DPL and ACE, respectively.

(c) Represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout the service territories for ComEd, PECO, BGE, Pepco and DPL. An AMI program has not been approved by the NJBPU for ACE in New Jersey. DPL and Pepco have received approval for recovery of deferred AMI program costs from the DCPSC and DPSC in the Delaware and DC service territories, and have requested recovery in pending distribution rate cases with the MDPSC for the Maryland service territories. As of September 30, 2016, the portion of deferred AMI program costs pending approval from the MDPSC is $32 million for BGE, $134 million for Pepco and $40 million for DPL, of which $75 million for Pepco and $14 million for DPL relates to retired legacy meters which are not earning a return and $3 million of post-test year costs for Pepco which are not earning a return.

(d) As of September 30, 2016, ComEd s regulatory asset of $232 million was comprised of $178 million for the 2014 2016 annual reconciliations and $54 million related to significant one-time events including $24 million of deferred storm costs, $11 million of Constellation and PHI merger and integration related costs and $19 million of smart meter related costs. As of December 31, 2015, ComEd s regulatory asset of $189 million was comprised of $142 million for the 2014 and 2015 annual reconciliations and $47 million related to significant one-time events, including $36 million of deferred storm costs and $11 million of Constellation merger and integration related costs. See Note 4 Merger, Acquisitions, and Dispositions of the Exelon 2015 Form 10-K for further information.

(e) Includes at Exelon and PHI the regulatory asset recorded at PHI for debt costs that are recoverable through the ratemaking process at Pepco, DPL, and ACE which were eliminated at Exelon and PHI as part of acquisition accounting.

(f) Includes the unamortized regulatory assets recorded for the difference between carrying value and fair value of long-term debt of BGE as of the Constellation merger date and at Exelon and PHI for the difference between carrying value and fair value of long-term debt of Pepco, DPL and ACE as of the PHI Merger date.

(g) Represents the regulatory asset recorded at Exelon and PHI offsetting the fair value adjustments related to Pepco s, DPL s and ACE s electricity and natural gas energy supply contracts recorded at PHI as of the PHI Merger date. Pepco, DPL and ACE are allowed full recovery of the costs of these contracts through their respective rate making processes.

(h) As of September 30, 2016, ComEd s regulatory asset of $31 million included $24 million associated with transmission costs recoverable through its FERC approved formula rate and $7 million of Constellation merger and integration costs

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

to be recovered upon FERC approval. As of September 30, 2016, ComEd s regulatory liability of $72 million included $43 million related to over-recovered energy costs and $29 million associated with revenues received for renewable energy requirements. As of December 31, 2015, ComEd s regulatory asset of $43 million included $5 million related to under-recovered energy costs, $31 million associated with transmission costs recoverable through its FERC approved formula rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2015, ComEd s regulatory liability of $53 million included $29 million related to over-recovered energy costs and $24 million associated with revenues received for renewable energy requirements.

(i) As of September 30, 2016, BGE s regulatory asset of $25 million included $3 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $19 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $1 million related to under-recovered natural gas costs. As of December 31, 2015, BGE s regulatory asset of $40 million included $12 million of costs associated with transmission costs recoverable through its FERC approved formula rate and $28 million related to under-recovered electric energy costs. As of December 31, 2015, BGE s regulatory liability of $18 million related to $14 million of over-recovered transmission costs and $5 million of over-recovered natural gas costs, offset by $1 million of abandonment costs to be recovered upon FERC approval.

(j) As of September 30, 2016, Pepco s regulatory asset of $1 million related to under-recovered electric energy costs. As of September 30, 2016, Pepco s regulatory liability of $17 million included $9 million of over-recovered transmission costs and $8 million of over-recovered electric energy costs. As of December 31, 2015, Pepco s regulatory asset of $9 million included $5 million of transmission costs recoverable through its FERC approved formula rate and $4 million of recoverable abandonment costs. As of December 31, 2015, Pepco s regulatory liability of $16 million included $14 million of over-recovered transmission costs and $2 million of over-recovered electric energy costs.

(k) As of September 30, 2016, DPL s regulatory asset of $8 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $7 million of under-recovered electric energy costs. As of September 30, 2016, DPL s regulatory liability of $11 million included $6 million of over-recovered electric energy costs and $5 million of over-recovered transmission costs. As of December 31, 2015, DPL s regulatory asset of $11 million included $7 million of transmission costs recoverable through its FERC approved formula rate, $3 million of recoverable abandonment costs, and $1 million of under-recovered electric energy costs. As of December 31, 2015, DPL s regulatory liability of $19 million included $4 million related to the over-recovered natural gas costs under the GCR mechanism, $4 million of over-recovered electric energy costs, and $11 million of over-recovered transmission costs.

(l) As of September 30, 2016, ACE s regulatory asset of $9 million included $4 million of transmission costs recoverable through its FERC approved formula rate and $5 million of under-recovered electric energy costs. As of September 30, 2016, ACE s regulatory liability of $12 million included $7 million of over-recovered transmission costs and $5 million of over-recovered electric energy costs. As of December 31, 2015, ACE s regulatory asset of $13 million included $2 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2015, ACE s regulatory liability of $8 million related to over-recovered transmission costs.

(m) As of September 30, 2016, BGE s regulatory asset of $10 million included $6 million of previously incurred PHI acquisition costs as authorized by the June 2016 rate case order.

(n) Represents previously incurred PHI acquisition costs expected to be recovered in distribution rates in the Maryland service territories of Pepco and DPL.

(o) Represents the electric and natural gas distribution costs recoverable from customers under BGE s decoupling mechanism. As of September 30, 2016, BGE had a regulatory liability of $5 million related to over-recovered natural gas revenue decoupling and $0 million related to over-recovered electric revenue decoupling. As of December 31, 2015, BGE had a regulatory asset of $30 million related to under-recovered electric revenue decoupling and a regulatory liability of $1 million related to over-recovered natural gas revenue decoupling.

(p) Represents the electric distribution costs recoverable from customers under Pepco s Maryland and District of Columbia decoupling mechanisms and DPL s Maryland decoupling mechanism.

(q) Represents the regulatory liability recorded at Exelon and PHI for deferred rent related to a lease that is recoverable through the ratemaking process at Pepco, DPL and ACE.

(r) As of September 30, 2016, PECO s regulatory liability of $59 million included $30 million related to over-recovered costs under the DSP program, $13 million related to the over-recovered natural gas costs under the PGC, $10 million related to over-recovered non-bypassable transmission service charges and $6 million related to over-recovered electric transmission costs. As of December 31, 2015, PECO s regulatory asset of $1 million related to under-recovered non-

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

bypassable transmission service charges. As of December 31, 2015, PECO s regulatory liability of $60 million included $35 million related to over-recovered costs under the DSP program, $22 million related to the over-recovered natural gas costs under the PGC and $3 million related to the over-recovered electric transmission costs.

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

ComEd, PECO, BGE, Pepco, DPL and ACE are required, under separate legislation and regulations in Illinois, Pennsylvania, Maryland, District of Columbia and New Jersey, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities consolidated billing. ComEd, BGE, Pepco and DPL purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon s, ComEd s, PECO s, BGE s, PHI s, Pepco s, DPL s and ACE s Consolidated Balance Sheets. The following tables provide information abo the purchased receivables of those companies as of September 30, 2016 and December 31, 2015.

					Successor			
As of September 30, 2016	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Purchased receivables[c]	$ 396	$ 123	$ 90	$ 66	$ 117	$ 79	$ 12	$ 26
Allowance for uncollectible accounts[a]	(36)	(17)	(7)	(6)	(6)	(4)		(2)
Purchased receivables, net	$ 360	$ 106	$ 83	$ 60	$ 111	$ 75	$ 12	$ 24

					Predecessor			
As of December 31, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Purchased receivables[b][c]	$ 229	$ 103	$ 67	$ 59	$ 100	$ 70	$ 11	$ 19
Allowance for uncollectible accounts[a]	(31)	(16)	(7)	(8)	(6)	(4)		(2)
Purchased receivables, net	$ 198	$ 87	$ 60	$ 51	$ 94	$ 66	$ 11	$ 17

(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) PECO s natural gas POR program became effective on January 1, 2012 and included a 1% discount on purchased receivables in order to recover the implementation costs of the program. The implementation costs were fully recovered and the 1% discount was reset to 0%, effective July 2015.

(c) Pepco s electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 2% depending on customer class, and Pepco s electric POR program in the District of Columbia included a discount on purchased receivables ranging from 0% to 6% depending on customer class. DPL s electric POR program in Maryland included a discount on purchased receivables ranging from 0% to 1% depending on customer class.

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

Long-Lived Assets (Exelon and Generation)

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 10 Debt and Credit Agreements) 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, see Note 10 Debt and Credit Agreements for additional information. As a result, the Upstream assets and liabilities are classified as held for sale on Exelon s and Generation s Consolidated Balance Sheets at September 30, 2016. See Note 4 Mergers, Acquisitions and Dispositions for additional information. 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.

Further declines in commodity prices or further developments with Generation s intended use or disposition of the assets could potentially result in future impairments of the Upstream assets.

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 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 merchant wind 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 retirement announcements of the Quad Cities and Clinton nuclear plants 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

regulatory solutions to ensure nuclear plants are fairly compensated for their carbon-free emissions, and the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules.

In 2015, Generation identified the Quad Cities, Clinton and Ginna nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. At that time, Exelon and Generation deferred retirement decisions on Clinton and Quad Cities until 2016 in order to participate in the 2016-2017 MISO primary reliability auction and the 2019-2020 PJM capacity auctions held in April and May 2016, respectively, as well as to provide Illinois policy makers with additional time to consider needed reforms and for MISO to consider market design changes to ensure long-term power system reliability in southern Illinois.

In April 2016, Clinton cleared the MISO primary reliability auction as a price taker for the 2016-2017 planning year. The resulting capacity price is insufficient to cover cash operating costs and a risk-adjusted rate of return to shareholders. In May 2016, Quad Cities did not clear in the PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period.

Based on these capacity auction results, and given the lack of progress on Illinois energy legislation and MISO market reforms, on June 2, 2016 Generation announced it will move forward to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively. The current Nuclear Regulatory Commission (NRC) licenses for Clinton and Quad Cities expire in 2026 and 2032, respectively. Generation is proceeding with the market and regulatory notifications that must be made to shut down the plants, including notification to the NRC on June 20, 2016, and filing of a deactivation notice with PJM for Quad Cities on July 6, 2016. Generation will formally notify MISO of its plans to close Clinton later this year.

In 2016, as a result of the plant retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $146 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 Clinton and Quad Cities primarily related to accelerated depreciation of plant assets (including any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions. Through September 30, 2016, Exelon s and Generation s results include an incremental $443 million of pre-tax expense for these items as summarized in the table below. Please refer to Note 12 Nuclear Decommissioning for additional detail on changes to the Nuclear decommissioning ARO balances resulting from the early retirement of Clinton and Quad Cities.

Income statement expense (pre-tax)		**September 30, 2016**
Depreciation and Amortization		
Accelerated depreciation[(a)]	$	459
Accelerated nuclear fuel amortization		37
Operating and Maintenance		
Increase ARO accretion, net of contractual offset[(b)]		2
Contractual offset for ARC depreciation[(b)]		(55)
Total	$	443

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The Three Mile Island (TMI) nuclear plant also did not clear in the May 2016 PJM capacity auction for the 2019-2020 planning year and will not receive capacity revenue for that period. This is the second consecutive year that TMI failed to clear the capacity auction. Although the plant is committed to operate through May 2019, the plant faces continued economic challenges and Exelon and Generation are exploring all options to return it to profitability. While a portion of the Byron nuclear plant s capacity did not clear the PJM 2019-2020 planning year capacity auction, the plant is committed to run through May 2020. The company s other nuclear plants in PJM cleared in the auction, except Oyster Creek, which did not participate in the auction given Exelon s and Generation s previous commitment to cease operation of the Oyster Creek nuclear plant by the end of 2019.

In New York, the Ginna and Nine Mile Point nuclear plants continue to face 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, and 2046 for Nine Mile Point Unit 2). On August 1, 2016, NYPSC issued an order adopting the Clean Energy Standard (CES), which would provide payments to Ginna and Nine Mile Point for the environmental attributes of their production. Subject to Ginna and Nine Mile Point entering into a satisfactory contract with the NYSERDA, as required under the CES, and subject to prevailing over any administrative or legal challenges, the CES will allow Ginna and Nine Mile Point to continue to operate at least through the life of the program (March 31, 2029). The approved RSSA currently requires Ginna to continue operating through the RSSA term expiring in March 2017. If Ginna does not plan to retire shortly after the expiration of the RSSA, notification to that effect was required to be filed with the NYPSC no later than September 30, 2016. 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. Negotiations with NYSERDA are ongoing and contract execution is currently targeted for completion in the fourth quarter of 2016. Refer to Note 5 Regulatory Matters for additional discussion on the Ginna RSSA and the New York CES.

The following table provides the balance sheet amounts as of September 30, 2016 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to current economic valuations and other factors.

(in millions)	TMI	Ginna	NMP
Asset Balances			
Materials and supplies inventory	$ 39	$ 31	$ 70
Nuclear fuel inventory, net	93	41	214
Completed plant, net	956	124	1,151
Construction work in progress	38	13	53
Liability Balances			
Asset retirement obligation	(492)	(667)	(780)
NRC License Renewal Term	2034	2029	2029 (unit 1)
			2046 (unit 2)

Assuming the successful implementation of the CES and its continued effectiveness, Generation and CENG would no longer consider Ginna and Nine Mile Point to be at heightened risk of early retirement; however, absent the CES for the full expected duration they will remain at heightened risk. The precise timing of an early retirement date for any of these plants, 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 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 obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) and preferred stock as of September 30, 2016 and December 31, 2015:

Exelon

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 567	$	$ 567	$	$ 567
Long-term debt (including amounts due within one year)[a]	34,842	1,075	34,272	2,279	37,626
Long-term debt to financing trusts[b]	642			692	692
SNF obligation	1,023		856		856

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 536	$ 3	$ 533	$	$ 536
Long-term debt (including amounts due within one year)[a]	25,145	931	23,644	1,349	25,924
Long-term debt to financing trusts[b]	641			673	673
SNF obligation	1,021		818		818

Generation

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 40	$	$ 40	$	$ 40
Long-term debt (including amounts due within one year)[a]	9,255		8,015	1,684	9,699
SNF obligation	1,023		856		856

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 29	$	$ 29	$	$ 29
Long-term debt (including amounts due within one year)[a]	8,959		7,767	1,349	9,116
SNF obligation	1,021		818		818

ComEd

September 30, 2016

Fair Value

	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 10	$	$ 10	$	$ 10
Long-term debt (including amounts due within one year)[(a)]	7,031		8,081		8,081
Long-term debt to financing trusts[(b)]	205			218	218

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 294	$	$ 294	$	$ 294
Long-term debt (including amounts due within one year)[a]	6,509		7,069		7,069
Long-term debt to financing trusts[b]	205			213	213

PECO

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,879	$	$ 3,266	$	$ 3,266
Long-term debt to financing trusts	184			207	207

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,580	$	$ 2,786	$	$ 2,786
Long-term debt to financing trusts	184			195	195

BGE

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,662	$	$ 2,966	$	$ 2,966
Long-term debt to financing trusts[b]	252			267	267

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 213	$ 3	$ 210	$	$ 213
Long-term debt (including amounts due within one year)[a]	1,858		2,044		2,044
Long-term debt to financing trusts[b]	252			264	264

PHI

	September 30, 2016				
Successor	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 517	$	$ 517	$	$ 517
Long-term debt (including amounts due within one year)	6,044		5,698	594	6,292

December 31, 2015

Predecessor	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 958	$	$ 958	$	$ 958
Long-term debt (including amounts due within one year)[(a)]	5,279		5,231	586	5,817
Preferred stock	183			183	183

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Pepco

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 2,350	$	$ 3,000	$ 2	$ 3,002

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 64	$	$ 64	$	$ 64
Long-term debt (including amounts due within one year)[a]	2,351		2,673		2,673

DPL

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 17	$	$ 17	$	$ 17
Long-term debt (including amounts due within one year)[a]	1,265		1,277	101	1,378

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 105	$	$ 105	$	$ 105
Long-term debt (including amounts due within one year)[a]	1,265		1,185	103	1,288

ACE

	September 30, 2016				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$ 1,167	$	$ 1,058	$ 299	$ 1,357

	December 31, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 5	$	$ 5	$	$ 5
Long-term debt (including amounts due within one year)[a]	1,201		1,044	280	1,324

(a) Includes unamortized debt issuance costs which are not fair valued of $204 million, $68 million, $47 million, $16 million, $15 million, $30 million, $10 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of September 30, 2016. Includes unamortized debt issuance costs of $180 million, $70 million, $38 million, $15 million, $9 million, $49 million, $31 million, $10 million, and $6 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, respectively, as of December 31, 2015.

(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 September 30, 2016 and December 31, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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 electric 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 PHI 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 project 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 project 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 estimated to be settled in 2025 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 2025.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Preferred Stock. The fair value of these securities is determined based on the carrying value of the shares per the Subscription Agreement between PHI and Exelon. See Note 16 Mezzanine Equity for further details.

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 significant transfers between Level 1 and Level 2 during the nine months ended September 30, 2016 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. See Note 2 New Accounting Pronouncements for additional information.

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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 September 30, 2016 and December 31, 2015:

	Generation					Exelon				
As of September 30, 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]	$ 94	$	$	$	$ 94	$ 1,645	$	$	$	$ 1,645
NDT fund investments										
Cash equivalents[b]	163	20			183	163	20			183
Equities	3,566	335		1,992	5,893	3,566	335		1,992	5,893
Fixed income										
Corporate debt		1,629	257		1,886		1,629	257		1,886
U.S. Treasury and agencies	1,363	33			1,396	1,363	33			1,396
Foreign governments		50			50		50			50
State and municipal debt		268			268		268			268
Other[c]		56		510	566		56		510	566
Fixed income subtotal	1,363	2,036	257	510	4,166	1,363	2,036	257	510	4,166
Middle market lending			436	23	459			436	23	459
Private equity				138	138				138	138
Real estate				306	306				306	306
NDT fund investments subtotal[d]	5,092	2,391	693	2,969	11,145	5,092	2,391	693	2,969	11,145
Pledged assets for Zion Station decommissioning										
Cash equivalents	14				14	14				14
Equities		1			1		1			1
Fixed income										
U.S. Treasury and agencies	28	2			30	28	2			30
Corporate debt		3			3		3			3
Fixed income subtotal	28	5			33	28	5			33
Middle market lending			19	68	87			19	68	87
Pledged assets for Zion Station decommissioning subtotal[e]	42	6	19	68	135	42	6	19	68	135
Rabbi trust investments										
Cash equivalents	10				10	83				83
Mutual funds	19				19	50				50
Fixed income							14			14
Life insurance contracts		18			18		64	21		85
Rabbi trust investments subtotal	29	18			47	133	78	21		232

Commodity derivative assets										
Economic hedges	883	2,790	1,948		5,621	884	2,790	1,948		5,622
Proprietary trading	11	51	36		98	11	51	36		98
Effect of netting and allocation of collateral[(f)]	(927)	(2,527)	(896)		(4,350)	(928)	(2,527)	(896)		(4,351)
Commodity derivative assets subtotal	(33)	314	1,088		1,369	(33)	314	1,088		1,369
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments							39			39
Economic hedges		28			28		28			28
Proprietary trading	7	1			8	7	1			8
Effect of netting and allocation of collateral	(4)	(17)			(21)	(4)	(17)			(21)
Interest rate and foreign currency derivative assets subtotal	3	12			15	3	51			54
Other investments			42		42			42		42
Total assets	5,227	2,741	1,842	3,037	12,847	6,882	2,840	1,863	3,037	14,622

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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 September 30, 2016	**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	(1,037)	(2,917)	(1,160)		(5,114)	(1,037)	(2,917)	(1,404)		(5,358)
Proprietary trading	(10)	(53)	(39)		(102)	(10)	(53)	(39)		(102)
Effect of netting and allocation of collateral[f]	1,012	2,777	1,046		4,835	1,012	2,777	1,046		4,835
Commodity derivative liabilities subtotal	(35)	(193)	(153)		(381)	(35)	(193)	(397)		(625)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(18)			(18)		(18)			(18)
Economic hedges		(19)			(19)		(19)			(19)
Proprietary trading	(6)				(6)	(6)				(6)
Effect of netting and allocation of collateral	8	16			24	8	16			24
Interest rate and foreign currency derivative liabilities subtotal	2	(21)			(19)	2	(21)			(19)
Deferred compensation obligation		(32)			(32)		(131)			(131)
Total liabilities	(33)	(246)	(153)		(432)	(33)	(345)	(397)		(775)
Total net assets	$ 5,194	$ 2,495	$ 1,689	$ 3,037	$ 12,415	$ 6,849	$ 2,495	$ 1,466	$ 3,037	$ 13,847

	Generation					Exelon				
As of December 31, 2015	**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]	$ 104	$	$	$	$ 104	$ 5,766	$	$	$	$ 5,766
NDT fund investments										
Cash equivalents[b]	219	92			311	219	92			311
Equities	3,008			1,894	4,902	3,008			1,894	4,902
Fixed income										
Corporate debt		1,824	242		2,066		1,824	242		2,066
U.S. Treasury and agencies	1,323	15			1,338	1,323	15			1,338
Foreign governments		61			61		61			61
State and municipal debt		326			326		326			326
Other[c]		147		390	537		147		390	537
Fixed income subtotal	1,323	2,373	242	390	4,328	1,323	2,373	242	390	4,328
Middle market lending			428		428			428		428
Private equity				125	125				125	125
Real estate				35	35				35	35
Other				216	216				216	216

NDT fund investments subtotal[d]	4,550	2,465	670	2,660	10,345	4,550	2,465	670	2,660	10,345
Pledged assets for Zion Station decommissioning										
Cash equivalents		17			17		17			17
Equities	1	5			6	1	5			6
Fixed income										
U.S. Treasury and agencies	6	2			8	6	2			8
Corporate debt		46			46		46			46
Other		1			1		1			1
Fixed income subtotal	6	49			55	6	49			55
Middle market lending			22	105	127			22	105	127
Pledged assets for Zion Station decommissioning subtotal[e]	7	71	22	105	205	7	71	22	105	205

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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, 2015	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Rabbi trust investments										
Mutual funds	17				17	48				48
Life insurance contracts		13			13		36			36
Rabbi trust investments subtotal	17	13			30	48	36			84
Commodity derivative assets										
Economic hedges	1,922	3,467	1,707		7,096	1,922	3,467	1,707		7,096
Proprietary trading	36	64	30		130	36	64	30		130
Effect of netting and allocation of collateral[f]	(1,964)	(2,629)	(564)		(5,157)	(1,964)	(2,629)	(564)		(5,157)
Commodity derivative assets subtotal	(6)	902	1,173		2,069	(6)	902	1,173		2,069
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments							25			25
Economic hedges		20			20		20			20
Proprietary trading	10	5			15	10	5			15
Effect of netting and allocation of collateral	(3)	(3)			(6)	(3)	(3)			(6)
Interest rate and foreign currency derivative assets subtotal	7	22			29	7	47			54
Other investments			33		33			33		33
Total assets	4,679	3,473	1,898	2,765	12,815	10,372	3,521	1,898	2,765	18,556
Liabilities										
Commodity derivative liabilities										
Economic hedges	(2,382)	(3,348)	(850)		(6,580)	(2,382)	(3,348)	(1,097)		(6,827)
Proprietary trading	(33)	(57)	(37)		(127)	(33)	(57)	(37)		(127)
Effect of netting and allocation of collateral[f]	2,440	3,186	765		6,391	2,440	3,186	765		6,391
Commodity derivative liabilities subtotal	25	(219)	(122)		(316)	25	(219)	(369)		(563)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(16)			(16)		(16)			(16)
Economic hedges		(3)			(3)		(3)			(3)
Proprietary trading	(12)				(12)	(12)				(12)
Effect of netting and allocation of collateral	12	3			15	12	3			15
Interest rate and foreign currency derivative liabilities subtotal		(16)			(16)		(16)			(16)
Deferred compensation obligation		(30)			(30)		(99)			(99)
Total liabilities	25	(265)	(122)		(362)	25	(334)	(369)		(678)

Total net assets	$ 4,704	$ 3,208	$ 1,776	$ 2,765	$ 12,453	$ 10,397	$ 3,187	$ 1,529	$ 2,765	$ 17,878

(a) Generation excludes cash of $282 million and $329 million at September 30, 2016 and December 31, 2015 and restricted cash of $161 million and $121 million at September 30, 2016 and December 31, 2015. Exelon excludes cash of $398 million and $763 million at September 30, 2016 and December 31, 2015 and restricted cash of $197 million and $178 million at September 30, 2016 and December 31, 2015 and includes long term restricted cash of $22 million at September 30, 2016, which is reported in other deferred debits on the balance sheet.

(b) Includes $64 million and $52 million of cash received from outstanding repurchase agreements at September 30, 2016 and December 31, 2015, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $(10) million and $(8) million, which have a total notional amount of $1,073 million and $1,236 million at September 30, 2016 and December 31, 2015, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the periods ended and do not represent the amount of the company s exposure to credit or market loss.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(d) Excludes net liabilities of $(69) million and $(3) million at September 30, 2016 and December 31, 2015, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(e) Excludes net assets of less than $1 million and $1 million at September 30, 2016 and December 31, 2015, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(f) Collateral posted to/(received) from counterparties totaled $85 million, $250 million and $150 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of September 30, 2016. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $476 million, $557 million and $201 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2015.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on ComEd s, PECO s and BGE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2016 and December 31, 2015:

	ComEd				PECO				BGE			
As of September 30, 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)]	$	$	$	$	$ 521	$	$	$ 521	$ 375	$	$	$ 375
Rabbi trust investments												
Mutual funds					7			7	4			4
Life insurance contracts						11		11				
Rabbi trust investments subtotal					7	11		18	4			4
Total assets					528	11		539	379			379
Liabilities												
Deferred compensation obligation		(8)		(8)		(10)		(10)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(244)	(244)								
Total liabilities		(8)	(244)	(252)		(10)		(10)		(4)		(4)
Total net assets (liabilities)	$	$ (8)	$ (244)	$ (252)	$ 528	$ 1	$	$ 529	$ 379	$ (4)	$	$ 375

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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, 2015	**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]	$ 29	$	$	$ 29	$ 271	$	$	$ 271	$ 25	$	$	$ 25
Rabbi trust investments												
Mutual funds					8			8	4			4
Life insurance contracts						12		12				
Rabbi trust investments subtotal					8	12		20	4			4
Total assets	29			29	279	12		291	29			29
Liabilities												
Deferred compensation obligation		(8)		(8)		(12)		(12)		(4)		(4)
Mark-to-market derivative liabilities[b]			(247)	(247)								
Total liabilities		(8)	(247)	(255)		(12)		(12)		(4)		(4)
Total net assets (liabilities)	$ 29	$ (8)	$ (247)	$ (226)	$ 279	$	$	$ 279	$ 29	$ (4)	$	$ 25

(a) ComEd excludes cash of $44 million and $38 million at September 30, 2016 and December 31, 2015 and restricted cash of $2 million and $2 million at September 30, 2016 and December 31, 2015. PECO excludes cash of $27 million and $27 million at September 30, 2016 and December 31, 2015 and $1 million of restricted cash at September 30, 2016. BGE excludes cash of $13 million and $6 million at September 30, 2016 and December 31, 2015 and restricted cash of $2 million and $2 million at September 30, 2016 and December 31, 2015 and includes long term restricted cash of $3 million at September 30, 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 $225 million, respectively, at September 30, 2016, and $23 million and $224 million, respectively, at December 31, 2015, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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PHI, Pepco, DPL and ACE

The following tables present assets and liabilities measured and recorded at fair value on PHI s, Pepco s, DPL s and ACE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of September 30, 2016 and December 31, 2015:

	Successor				*Predecessor*			
	As of September 30, 2016				**As of December 31, 2015**			
PHI	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 347	$	$	$ 347	$ 42	$	$	$ 42
Mark-to-market derivative assets[(b)(c)]	1			1			18	18
Effect of netting and allocation of collateral	(1)			(1)				
Mark-to-market derivative assets subtotal							18	18
Rabbi trust investments								
Cash equivalents	73			73	12			12
Fixed income		14		14		15		15
Life insurance contracts		22	21	43		27	19	46
Rabbi trust investments subtotal	73	36	21	130	12	42	19	73
Total assets	420	36	21	477	54	42	37	133
Liabilities								
Deferred compensation obligation		(28)		(28)		(30)		(30)
Mark-to-market derivative liabilities[(b)]					(2)			(2)
Effect of netting and allocation of collateral					2			2
Mark-to-market derivative liabilities subtotal								
Total liabilities		(28)		(28)		(30)		(30)
Total net assets	$ 420	$ 8	$ 21	$ 449	$ 54	$ 12	$ 37	$ 103

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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As of September 30, 2016	**Pepco** Level 1	Level 2	Level 3	Total	**DPL** Level 1	Level 2	Level 3	Total	**ACE** Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[a]	$ 127	$	$	$ 127	$	$	$	$	$ 194	$	$	$ 194
Mark-to-market derivative assets[b]					1			1				
Effect of netting and allocation of collateral					(1)			(1)				
Mark-to-market derivative assets subtotal												
Rabbi trust investments												
Cash equivalents	43			43								
Fixed income		14		14								
Life insurance contracts		22	21	43								
Rabbi trust investments subtotal	43	36	21	100								
Total assets	170	36	21	227					194			194
Liabilities												
Deferred compensation obligation		(5)		(5)		(1)		(1)				
Total liabilities		(5)		(5)		(1)		(1)				
Total net assets (liabilities)	$ 170	$ 31	$ 21	$ 222	$	$ (1)	$	$ (1)	$ 194	$	$	$ 194

As of December 31, 2015	**Pepco** Level 1	Level 2	Level 3	Total	**DPL** Level 1	Level 2	Level 3	Total	**ACE** Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ 2	$	$	$ 2	$	$	$	$	$ 30	$	$	$ 30
Rabbi trust investments												
Cash equivalents	11			11								
Fixed income		15		15								
Life insurance contracts		23	19	42								
Rabbi trust investments subtotal	11	38	19	68								
Total assets	13	38	19	70					30			30
Liabilities												
Deferred compensation obligation		(6)		(6)		(1)		(1)				
Mark-to-market derivative liabilities[b]					(2)			(2)				
Effect of netting and allocation of collateral					2			2				
Mark-to-market derivative liabilities subtotal												

Total liabilities		(6)		(6)		(1)		(1)				
Total net assets (liabilities)	$ 13	$ 32	$ 19	$ 64	$	$ (1)	$	$ (1)	$ 30	$	$	$ 30

(a) PHI excludes cash of $20 million and $16 million at September 30, 2016 and December 31, 2015 and includes long term restricted cash of $19 million and $18 million at September 30, 2016 and December 31, 2015 which is reported in other deferred debits on the balance sheet. Pepco excludes cash of $8 million and $5 million at September 30, 2016 and December 31, 2015. DPL excludes cash of $4 million and $5 million at September 30, 2016 and December 31, 2015. ACE excludes cash of $5 million and $3 million at September 30, 2016 and December 31, 2015 and includes long term restricted cash of $19 million and $18 million at September 30, 2016 and December 31, 2015 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)

(c) Prior to the PHI Merger, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock outstanding as of December 31, 2015. See Note 16 Mezzanine Equity for additional information. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2016 and 2015:

	Generation					ComEd	*Successor* PHI		Exelon
Three Months Ended September 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 June 30, 2016	$ 715	$ 25	$ 609	$ 37	$ 1,386	$ (221)	$ 20	$	$ 1,185
Total realized / unrealized gains (losses)									
Included in net income	(4)		95[b]	1	92		1		93
Included in noncurrent payables to affiliates	6				6			(6)	
Included in payable for Zion Station decommissioning		(1)			(1)				(1)
Included in regulatory assets						(23)		6	(17)
Change in collateral			31		31				31
Purchases, sales, issuances and settlements									
Purchases	4		207[d]	3	214				214
Sales		(5)	(2)		(7)				(7)
Issuances									
Settlements	(28)				(28)				(28)
Transfers into Level 3			(1)	1					
Transfers out of Level 3			(4)		(4)				(4)
Balance at September 30, 2016	$ 693	$ 19	$ 935	$ 42	$ 1,689	$ (244)	$ 21	$	$ 1,466
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2016	$ 3	$	$ 285	$	$ 288	$	$	$	$ 288

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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[c]		Exelon
Nine Months Ended September 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 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	2		(339)[b]	1	(336)		2		(334)
Included in noncurrent payables to affiliates	18				18			(18)	
Included in payable for Zion Station decommissioning		1			1				1
Included in regulatory assets/liabilities						3		18	21
Change in collateral			(51)		(51)				(51)
Purchases, sales, issuances and settlements									
Purchases	123	1	289[d]	7	420				420
Sales	(1)	(5)	(5)		(11)				(11)
Issuances							(1)		(1)
Settlements	(119)				(119)				(119)
Transfers into Level 3			1	1	2				2
Transfers out of Level 3			(11)		(11)				(11)
Balance as of September 30, 2016	$ 693	$ 19	$ 935	$ 42	$ 1,689	$ (244)	$ 21	$	$ 1,466
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2016	$ 7	$	$ 240	$	$ 247	$	$ 1	$	$ 248

(a) Includes $25 million of decreases in fair value and realized losses due to settlements of $2 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2016. Includes $10 million of decreases in fair value and realized losses due to settlements of $13 million for the nine months ended September 30, 2016.

(b) Includes a reduction for the reclassification of $190 million and $579 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2016, respectively.

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

(d) Includes $168 million of fair value from contracts acquired as a result of portfolio acquisitions.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended September 30, 2015	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[c]	Eliminated in Consolidation	Exelon Total
Balance as of June 30, 2015	$ 667	$ 41	$ 1,021	$ 30	$ 1,759	$ (223)	$	$ 1,536
Total realized / unrealized gains (losses)								
Included in net income			(48)[b]		(48)			(48)
Included in noncurrent payables to affiliates								
Included in payable for Zion Station decommissioning		1			1			1
Included in regulatory assets						(20)		(20)
Change in collateral			90		90			90
Purchases, sales, issuances and settlements								
Purchases	15		50	2	67			67
Sales		(13)	(5)		(18)			(18)
Settlements	(13)				(13)			(13)
Transfers into Level 3			69		69			69
Transfers out of Level 3			(3)		(3)			(3)
Balance as of September 30, 2015	$ 669	$ 29	$ 1,174	$ 32	$ 1,904	$ (243)	$	$ 1,661
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2015	$ (1)	$	$ 181	$	$ 180	$	$	$ 180

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2015	Generation NDT Fund Investments	Generation Pledged Assets for Zion Station Decommissioning	Generation Mark-to-Market Derivatives	Generation Other Investments	Generation Total Generation	ComEd Mark-to-Market Derivatives[a]	Eliminated in Consolidation	Exelon Total
Balance as of December 31, 2014	$ 605	$ 50	$ 1,050	$ 3	$ 1,708	$ (207)	$	$ 1,501
Total realized / unrealized gains (losses)								
Included in net income	4		(87)[b]		(83)			(83)
Included in noncurrent payables to affiliates	17				17		(17)	
Included in payable for Zion Station decommissioning		2			2			2
Included in regulatory assets						(36)	17	(19)
Change in collateral			72		72			72
Purchases, sales, issuances and settlements								
Purchases	122	1	107	29	259			259
Sales	(8)	(24)	(10)		(42)			(42)
Settlements	(75)				(75)			(75)
Transfers into Level 3	4		80		84			84
Transfers out of Level 3			(38)		(38)			(38)
Balance as of September 30, 2015	$ 669	$ 29	$ 1,174	$ 32	$ 1,904	$ (243)	$	$ 1,661
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2015	$ 2	$	$ 536	$	$ 538	$	$	$ 538

(a) Includes $19 million of decreases in fair value and a reduction for realized gains 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 September 30, 2015. Includes $44 million of decreases in fair value and an increase for realized losses due to settlements of $8 million for the nine months ended September 30, 2015.

(b) Includes a reduction for the reclassification of $229 million and $623 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2015, respectively.

PHI	*Successor* Three Months Ended September 30, 2016 Life Insurance Contracts	*Predecessor* Three Months Ended September 30, 2015 Preferred Stock	*Predecessor* Three Months Ended September 30, 2015 Life Insurance Contracts
Beginning Balance	$ 20	$ 3	$ 20
Total realized / unrealized gains (losses)			
Included in net income	1	15	1
Purchases, sales, issuances and settlements			
Issuances			(2)
Settlements			

Ending Balance	$	21	$ 18		$	19
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	$		$ 15		$	

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PHI	*Successor* March 24, 2016 to September 30, 2016 Life Insurance Contracts	*Predecessor* January 1, 2016 to March 23, 2016 Preferred Stock	*Predecessor* January 1, 2016 to March 23, 2016 Life Insurance Contracts	*Predecessor* Nine Months Ended September 30, 2015 Preferred Stock	*Predecessor* Nine Months Ended September 30, 2015 Life Insurance Contracts
Beginning Balance	$ 20	$ 18	$ 19	$ 3	$ 19
Total realized / unrealized gains (losses)					
Included in net income	2	(18)	1	15	4
Purchases, sales, issuances and settlements					
Issuances	(1)				(3)
Settlements					(1)
Ending Balance	$ 21	$	$ 20	$ 18	$ 19
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	$	$ 1	$ 15	$ 2

	Three Months Ended September 30, 2016 Pepco Life Insurance Contracts	Three Months Ended September 30, 2015 Pepco Life Insurance Contracts
Beginning Balance	$ 20	$ 20
Total realized / unrealized gains (losses)		
Included in net income	1	1
Purchases, sales, issuances and settlements		
Issuances		(3)
Settlements		
Ending Balance	$ 21	$ 18
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	$	$

	Nine Months Ended September 30, 2016 Pepco Life Insurance Contracts	Nine Months Ended September 30, 2015 Pepco Life Insurance Contracts	Nine Months Ended September 30, 2015 DPL Life Insurance Contracts
Beginning Balance	$ 19	$ 18	$ 1
Total realized / unrealized gains (losses)			
Included in net income	3	4	
Purchases, sales, issuances and settlements			
Issuances	(1)	(4)	

Settlements						(1)
Ending Balance	$	21	$	18	$	
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	$	2	$	2	$	

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and nine months ended September 30, 2016 and 2015:

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended September 30, 2016	$ 180	$ (85)	$ (4)	$ 180	$ (85)	$ (3)
Total gains (losses) included in net income for the nine months ended September 30, 2016	(232)	(107)	2	(232)	(107)	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2016	323	(38)	3	323	(38)	3
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2016	303	(63)	7	303	(63)	8

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended September 30, 2015	$ (4)	$ (44)	$	$ (4)	$ (44)	$
Total gains (losses) included in net income for the nine months ended September 30, 2015	(31)	(56)	4	(31)	(56)	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2015	198	(17)	(1)	198	(17)	(1)
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2015	538	(2)	2	538	(2)	2

	Successor PHI	*Predecessor* PHI	Pepco	
	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015
	Other, net	Other, net	Other, net	
Total gains (losses) included in net income	$ 1	$ 16	$ 1	$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held		15		

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Successor PHI	*Predecessor* PHI		Pepco	
	March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
	Other, net	Other, net		Other, net	
Total gains (losses) included in net income	$ 2	$ (17)	$ 19	$ 3	$ 4
Change in the unrealized gains (losses) relating to assets and liabilities held	1	1	17	2	2

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation and the life insurance contracts held by 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, as further described in Note 16 Mezzanine Equity, 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 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, Fixed Income and Other. 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 interest rate swaps to manage risk are recorded at fair value. Derivative instruments 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 not highly observable.

As of September 30, 2016, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately $170 million, $73 million, and $220 million, respectively. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of September 30, 2016. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of September 30, 2016, 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 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

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

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 predominately 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.

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 and DPL)

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

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

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation s own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument s market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $2.81 and $0.36 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. See ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrants mark-to-market derivative assets and liabilities.

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.

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

Type of trade	Fair Value at September 30, 2016	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives Economic Hedges (Exelon and Generation)(a)(c)	$ 788	Discounted Cash Flow	Forward power price	$6	$130
			Forward gas price	$1.24	$9.53
		Option Model	Volatility percentage	5%	115%
Mark-to-market derivatives Proprietary trading (Exelon and Generation)(a)(c)	$ (3)	Discounted Cash Flow	Forward power price	$15	$68
Mark-to-market derivatives (Exelon and ComEd)	$ (244)	Discounted Cash Flow	Forward heat rate(b)	8x	9x
			Marketability reserve	3%	8%
			Renewable factor	86%	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 $150 million as of September 30, 2016.

Type of trade	Fair Value at December 31, 2015	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives Economic Hedges (Exelon and Generation)(a)(c)	$ 857	Discounted Cash Flow	Forward power price	$11	$88
			Forward gas price	$1.18	$8.95
		Option Model	Volatility percentage	5%	152%
Mark-to-market derivatives Proprietary trading (Exelon and Generation)(a)(c)	$ (7)	Discounted Cash Flow	Forward power price	$13	$78

Mark-to-market derivatives (Exelon and ComEd)	$	(247)	Discounted Cash Flow	Forward heat rate[b]	9x	10x
				Marketability reserve	3.5%	7%
				Renewable factor	87%	128%

(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 $201 million as of December 31, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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 valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies 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. For a sample of its Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

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 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 September 30, 2016, the proportion of expected generation hedged for the major reportable segments is 98%-101%, 85%-88% and 54%-57% for 2016, 2017 and 2018, 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 for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales to the Utility Registrants 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 2015 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 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 25% 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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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 1,506 GWhs and 4,015 GWhs for the three and nine months ended September 30, 2016, respectively, and 1,913 GWhs and 5,378 GWhs for the three and nine months ended September 30, 2015, 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 September 30, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had $672 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a 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 $5 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2016. 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 September 30, 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)	$	$ 15	$ 4	$ (10)	$ 9	$	$ 9
Mark-to-market derivative assets (noncurrent assets)		13	4	(11)	6	39	45
Total mark-to-market derivative assets		28	8	(21)	15	39	54
Mark-to-market derivative liabilities (current liabilities)	(8)	(10)	(3)	12	(9)		(9)
Mark-to-market derivative liabilities (noncurrent liabilities)	(10)	(9)	(3)	12	(10)		(10)
Total mark-to-market derivative liabilities	(18)	(19)	(6)	24	(19)		(19)

Total mark-to-market derivative net assets (liabilities)	$ (18)	$ 9	$ 2	$ 3	$ (4)	$ 39	$ 35

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 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.

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2015:

	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)	$	$ 10	$ 10	$ (5)	$ 15	$	$ 15
Mark-to-market derivative assets (noncurrent assets)		10	5	(1)	14	25	39
Total mark-to-market derivative assets		20	15	(6)	29	25	54
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(9)	11	(8)		(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(8)	(1)	(3)	4	(8)		(8)
Total mark-to-market derivative liabilities	(16)	(3)	(12)	15	(16)		(16)
Total mark-to-market derivative net assets (liabilities)	$ (16)	$ 17	$ 3	$ 9	$ 13	$ 25	$ 38

(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 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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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:

		Three Months Ended September 30,			
	Income Statement Location	**2016**	**2015**	**2016**	**2015**
		Gain (loss) on Swaps		**Gain (loss) on Borrowings**	
Exelon	Interest expense	$ (8)	$ 16	$ 14	$ (13)

		Nine Months Ended September 30,			
	Income Statement Location	**2016**	**2015**	**2016**	**2015**
		Gain (loss) on Swaps		**Gain (loss) on Borrowings**	
Generation	Interest expense[(a)]	$	$ (1)	$	$
Exelon	Interest expense	15	15	(3)	(4)

(a) For the nine months ended September 30, 2015, the loss on Generation swaps included $1 million realized in earnings with an immaterial amount excluded from hedge effectiveness testing.

At September 30, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $39 million. At December 31, 2015, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $25 million. During the three and nine months ended September 30, 2016, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a $6 million and a $12 million gain, respectively.

Cash Flow Hedges. During the second quarter of 2016, Exelon entered into $90 million of floating-to-fixed forward starting interest rate swaps 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 third quarter of 2016 upon issuance of the debt. Exelon did not recognize a gain or loss as a result of the termination.

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 the anticipated issuance of debt. 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 for additional information.

During the first quarter of 2016, Exelon entered into $100 million of floating-to-fixed forward starting interest rate swap 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 third quarter of 2014, ExGen Texas Power, LLC, 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 2015 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $496 million as of September 30, 2016 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At September 30, 2016, the subsidiary had a $15 million derivative liability related to the swap.

During the first quarter of 2014, ExGen Renewables I, LLC, 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 2015 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $176 million as of September 30, 2016 and expire in 2020. The swaps are designated as cash flow hedges. At September 30, 2016, the subsidiary had a $3 million derivative liability related to the swaps.

During the second quarter of 2002, PHI entered into treasury rate lock transactions in anticipation of the issuance of several series of fixed-rate debt commencing in August 2002 to manage a portion of its interest rate exposure. Upon issuance of the fixed-rate debt in August 2002, the treasury rate locks were terminated at a loss and the loss was deferred in AOCI. As a result of the PHI Merger, the remaining unamortized deferred loss recorded in AOCI was adjusted to zero through application of purchase accounting.

During the three and nine months ended September 30, 2016 and 2015, 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 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 2015 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the issuance of debt, Generation terminated the swaps. The total notional amount of the swaps were $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 2015 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the issuance 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.

During the second quarter 2015, upon the issuance of debt, Exelon terminated $2,400 million of floating-to-fixed forward starting interest rate swaps. As a result of the termination of the swaps, Exelon realized a $64 million loss during the second quarter of 2015.

At September 30, 2016, Generation had no notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $85 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international commodity transactions 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 initial margin on exchange positions, is aggregated in the collateral and netting column. As of September 30, 2016 and December 31, 2015, $5 million and $3 million of cash collateral held and posted, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of September 30, 2016:

									Successor	
	Generation				ComEd	DPL			PHI	Exelon
			Collateral				Collateral			
	Economic	Proprietary	and		Economic	Economic	and			Total
Derivatives	**Hedges**	**Trading**	**Netting[a]**	**Subtotal[b]**	**Hedges[c]**	**Hedges[d]**	**Netting[a]**	**Subtotal**	**Subtotal**	**Derivatives**
Mark-to-market derivative assets (current assets)	$ 3,482	$ 67	$ (2,804)	$ 745	$	$ 1	$ (1)	$	$	$ 745
Mark-to-market derivative assets (noncurrent assets)	2,139	31	(1,546)	624						624
Total mark-to-market derivative assets	5,621	98	(4,350)	1,369		1	(1)			1,369
Mark-to-market derivative liabilities (current liabilities)	(3,229)	(61)	3,096	(194)	(19)					(213)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,885)	(41)	1,739	(187)	(225)					(412)
Total mark-to-market derivative liabilities	(5,114)	(102)	4,835	(381)	(244)					(625)
Total mark-to-market derivative net assets (liabilities)	$ 507	$ (4)	$ 485	$ 988	$ (244)	$ 1	$ (1)	$	$	$ 744

(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 $135 million and $84 million, respectively, and current and noncurrent liabilities are shown net of collateral of $156 million and $110 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 September 30, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2015:

	Generation				ComEd	Exelon	DPL			*Predecessor* PHI Corporate	PHI
Description	**Economic Hedges**	**Proprietary Trading**	**Collateral and Netting[a]**	**Subtotal[b]**	**Economic Hedges[c]**	**Total Derivatives**	**Economic Hedges[e]**	**Collateral and Netting[a]**	**Subtotal**	**Other[d]**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 5,236	$ 108	$ (3,994)	$ 1,350	$	$ 1,350	$	$	$	$ 18	$ 18
Mark-to-market derivative assets (noncurrent assets)	1,860	22	(1,163)	719		719					
Total mark-to-market derivative assets	7,096	130	(5,157)	2,069		2,069				18	18
Mark-to-market derivative liabilities (current liabilities)	(4,907)	(94)	4,827	(174)	(23)	(197)	(2)	2			
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,673)	(33)	1,564	(142)	(224)	(366)					
Total mark-to-market derivative liabilities	(6,580)	(127)	6,391	(316)	(247)	(563)	(2)	2			
Total mark-to-market derivative net assets (liabilities)	$ 516	$ 3	$ 1,234	$ 1,753	$ (247)	$ 1,506	$ (2)	$ 2	$	$ 18	$ 18

(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 $352 million and $180 million, respectively, and current and noncurrent liabilities are shown net of collateral of $480 million and $222 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,234 million at December 31, 2015.

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

(d) Prior to the PHI Merger, PHI recorded derivative assets for the embedded call and redemption features on the shares of Preferred Stock outstanding as of December 31, 2015. See Note 16 Mezzanine Equity for additional information. As a result of the PHI Merger, the PHI preferred stock derivative was reduced to zero as of March 23, 2016.

(e) 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)

Cash Flow Hedges (Exelon and Generation). The tables below provide the activity of AOCI related to cash flow hedges for the nine months ended September 30, 2016 and 2015, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from AOCI, 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 September 30, 2016	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
AOCI derivative loss at June 30, 2016		$ (25)	$ (26)
Effective portion of changes in fair value		1	3
AOCI derivative loss at September 30, 2016		$ (24)	$ (23)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Nine Months Ended September 30, 2016	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
Accumulated OCI derivative loss at December 31, 2015		$ (21)	$ (19)
Effective portion of changes in fair value			(1)
Reclassifications from AOCI to net income	Interest Expense	(3)[a]	(3)[a]
Accumulated OCI derivative loss at September 30, 2016		$ (24)	$ (23)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2015	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
AOCI derivative loss at June 30, 2015		(21)	$ (19)
Effective portion of changes in fair value		(7)	(8)
Reclassifications from AOCI to net income	Interest Expense	3	3
AOCI derivative loss at September 30, 2015		$ (25)	$ (24)

Nine Months Ended September 30, 2015	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation — Total Cash Flow Hedges	Exelon — Total Cash Flow Hedges
Accumulated OCI derivative loss at December 31, 2014		$ (18)	$ (28)
Effective portion of changes in fair value		(13)	(18)
Reclassifications from AOCI to net income	Other, net		16[(b)]
Reclassifications from AOCI to net income	Interest Expense	8	8
Reclassifications from AOCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative loss at September 30, 2015		$ (25)	$ (24)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Amount is net of related income tax expense of $2 million for the nine months ended September 30, 2016.
(b) Amount is net of related income tax expense of $10 million for the nine months ended September 30, 2015.

The effect of Exelon s and Generation s former energy-related cash flow hedge activity on pre-tax earnings based on the reclassification adjustment from AOCI to earnings was a $2 million pre-tax gain for the nine months ended September 30, 2015. There were no gains recognized for the three months ended September 30, 2015. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods relating to energy-related hedges positions as all were de-designated prior to the Constellation merger date.

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 nine months ended September 30, 2016 and 2015, 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 at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Exelon
Three Months Ended September 30, 2016	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ 280	$ (73)	$ 207	$ 207
Reclassification to realized at settlement of commodity positions	(92)	(26)	(118)	(118)
Net commodity mark-to-market gains (losses)	188	(99)	89	89
Change in fair value of treasury positions	1		1	1
Reclassification to realized at settlement of treasury positions	(2)		(2)	(2)
Net treasury mark-to-market gains (losses)	(1)		(1)	(1)
Net mark-to-market gains (losses)	$ 187	$ (99)	$ 88	$ 88

	Generation			Exelon
Nine Months Ended September 30, 2016	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Total**
Change in fair value of commodity positions	$ 127	$ 36	$ 163	$ 163
Reclassification to realized at settlement of commodity positions	(484)	217	(267)	(267)
Net commodity mark-to-market gains (losses)	(357)	253	(104)	(104)

Change in fair value of treasury positions	(3)		(3)	(3)
Reclassification to realized at settlement of treasury positions	(6)		(6)	(6)
Net treasury mark-to-market gains (losses)	(9)		(9)	(9)
Net mark-to-market gains (losses)	$ (366)	$ 253	$ (113)	$ (113)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended September 30, 2015	Generation Operating Revenues	Generation Purchased Power and Fuel	Total	Exelon Corporate Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 136	$ (178)	$ (42)	$	$ (42)
Reclassification to realized at settlement of commodity positions	(143)	46	(97)		(97)
Net commodity mark-to-market gains (losses)	(7)	(132)	(139)		(139)
Change in fair value of treasury positions	2		2		2
Reclassification to realized at settlement of treasury positions	(2)		(2)		(2)
Net treasury mark-to-market gains (losses)					
Net mark-to-market gains (losses)	$ (7)	$ (132)	$ (139)	$	$ (139)

Nine Months Ended September 30, 2015	Generation Operating Revenues	Generation Purchased Power and Fuel	Total	Exelon Corporate Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 513	$ (163)	$ 350	$	$ 350
Reclassification to realized at settlement of commodity positions	(347)	249	(98)		(98)
Net commodity mark-to-market gains (losses)	166	86	252		252
Change in fair value of treasury positions	12		12	36	48
Reclassification to realized at settlement of treasury positions	(6)		(6)	64	58
Net treasury mark-to-market gains (losses)	6		6	100	106
Net mark-to-market gains (losses)	$ 172	$ 86	$ 258	$ 100	$ 358

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 2016 and 2015, 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 revenue 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 at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Change in fair value of commodity positions	$ 4	$ (4)		