

EXELON CORP  
Form 10-Q  
May 10, 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 March 31, 2016**

or

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

<b>Commission</b>	<b>Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number</b>	<b>IRS Employer Identification Number</b>
<b>File Number</b>		
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

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000-16844	(312) 394-4321 PECO ENERGY COMPANY (a Pennsylvania corporation)  P.O. Box 8699  2301 Market Street  Philadelphia, Pennsylvania 19101-8699	23-0970240
1-1910	(215) 841-4000 BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation)  2 Center Plaza  110 West Fayette Street  Baltimore, Maryland 21201-3708	52-0280210
001-31403	(410) 234-5000 PEPCO HOLDINGS LLC (a Delaware limited liability company)  701 Ninth Street, N.W.  Washington, District of Columbia 20068	52-2297449
001-01072	(202) 872-2000 POTOMAC ELECTRIC POWER COMPANY (a District of Columbia and Virginia corporation)  701 Ninth Street, N.W.  Washington, District of Columbia 20068	53-0127880
001-01405	(202) 872-2000 DELMARVA POWER & LIGHT COMPANY (a Delaware and Virginia corporation)  500 North Wakefield Drive  Newark, Delaware 19702	51-0084283
001-03559	(202) 872-2000 ATLANTIC CITY ELECTRIC COMPANY (a New Jersey corporation)  500 North Wakefield Drive  Newark, Delaware 19702  (202) 872-2000	21-0398280

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes  No

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

The number of shares outstanding of each registrant's common stock as of March 31, 2016 was:

Exelon Corporation Common Stock, without par value	887,313,966
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, \$12.50 par value	127,017,042
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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**Table of Contents****GLOSSARY OF TERMS AND ABBREVIATIONS****Exelon Corporation and Related Entities**

<i>Exelon</i>	Exelon Corporation
<i>Generation</i>	Exelon Generation Company, LLC
<i>ComEd</i>	Commonwealth Edison Company
<i>PECO</i>	PECO Energy Company
<i>BGE</i>	Baltimore Gas and Electric Company
<i>Pepco Holdings or PHI</i>	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
<i>Pepco</i>	Potomac Electric Power Company
<i>Pepco Energy Services or PES</i>	Pepco Energy Services, Inc. and its subsidiaries
<i>PCI</i>	Potomac Capital Investment Corporation and its subsidiaries
<i>DPL</i>	Delmarva Power & Light Company
<i>ACE</i>	Atlantic City Electric Company
<i>ACE Funding or ATF</i>	Atlantic City Electric Transition Funding LLC
<i>BSC</i>	Exelon Business Services Company, LLC
<i>PHISCO</i>	PHI Service Company
<i>Exelon Corporate</i>	Exelon in its corporate capacity as a holding company
<i>PHI Corporate</i>	PHI in its corporate capacity as a holding company
<i>CENG</i>	Constellation Energy Nuclear Group, LLC
<i>Constellation</i>	Constellation Energy Group, Inc.
<i>Antelope Valley</i>	Antelope Valley Solar Ranch One
<i>Exelon Transmission Company</i>	Exelon Transmission Company, LLC
<i>Exelon Wind</i>	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
<i>Ventures</i>	Exelon Ventures Company, LLC
<i>AmerGen</i>	AmerGen Energy Company, LLC
<i>BondCo</i>	RSB BondCo LLC
<i>PEC L.P.</i>	PECO Energy Capital, L.P.
<i>PECO Trust III</i>	PECO Capital Trust III
<i>PECO Trust IV</i>	PECO Energy Capital Trust IV
<i>PETT</i>	PECO Energy Transition Trust
<i>Registrants</i>	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
<i>Utility Registrants</i>	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
<i>Legacy PHI</i>	PHI, Pepco, DPL and ACE, collectively

**Other Terms and Abbreviations**

<i>Note of the Exelon 2015 Form 10-K</i>	Reference to specific Combined Note to Consolidated Financial Statements within Exelon's 2015 Annual Report on Form 10-K
<i>Note of the PHI 2015 Form 10-K</i>	Reference to specific Note to Consolidated Financial Statements within Legacy PHI's 2015 Annual Report on Form 10-K
<i>1998 restructuring settlement</i>	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
<i>Act 11</i>	Pennsylvania Act 11 of 2012
<i>Act 129</i>	Pennsylvania Act 129 of 2008
<i>AEC</i>	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
<i>AEPS</i>	Pennsylvania Alternative Energy Portfolio Standards
<i>AEPS Act</i>	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
<i>AESO</i>	Alberta Electric Systems Operator

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<i>AFUDC</i>	Allowance for Funds Used During Construction
<i>ALJ</i>	Administrative Law Judge
<i>AMI</i>	Advanced Metering Infrastructure
<i>AMP</i>	Advanced Metering Program
<i>ARC</i>	Asset Retirement Cost
<i>ARO</i>	Asset Retirement Obligation
<i>ARP</i>	Title IV Acid Rain Program
<i>ARRA of 2009</i>	American Recovery and Reinvestment Act of 2009
<i>ASC</i>	Accounting Standards Codification
<i>BGS</i>	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)
<i>Block contracts</i>	Forward Purchase Energy Block Contracts
<i>CAIR</i>	Clean Air Interstate Rule
<i>CAISO</i>	California ISO
<i>CAMR</i>	Federal Clean Air Mercury Rule
<i>CERCLA</i>	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
<i>CFL</i>	Compact Fluorescent Light
<i>Clean Air Act</i>	Clean Air Act of 1963, as amended
<i>Clean Water Act</i>	Federal Water Pollution Control Amendments of 1972, as amended
<i>Competition Act</i>	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
<i>Conectiv</i>	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
<i>Conectiv Energy</i>	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
<i>Contract EDCs</i>	Pepco, DPL and BGE, the Maryland utilities required by the MDPSC to enter into a contract for new generation
<i>CPI</i>	Consumer Price Index
<i>CPUC</i>	California Public Utilities Commission
<i>CSAPR</i>	Cross-State Air Pollution Rule
<i>CTA</i>	Consolidated tax adjustment
<i>CTC</i>	Competitive Transition Charge
<i>D.C. Circuit Court</i>	United States Court of Appeals for the District of Columbia Circuit
<i>DCPSC</i>	District of Columbia Public Service Commission
<i>DC PLUG</i>	District of Columbia Power Line Undergrounding
<i>Default Electricity Supply</i>	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
<i>Default Electricity Supply Revenue</i>	Revenue primarily from Default Electricity Supply
<i>DOE</i>	United States Department of Energy
<i>DOJ</i>	United States Department of Justice
<i>DPSC</i>	Delaware Public Service Commission
<i>DRP</i>	Direct Stock Purchase and Dividend Reinvestment Plan
<i>DSP</i>	Default Service Provider
<i>DSP Program</i>	Default Service Provider Program
<i>EDCs</i>	Electric distribution companies



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<i>EDF</i>	Electricite de France SA and its subsidiaries
<i>EE&amp;C</i>	Energy Efficiency and Conservation/Demand Response
<i>EGS</i>	Electric Generation Supplier
<i>EGTP</i>	ExGen Texas Power, LLC
<i>EIMA</i>	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
<i>EmPower Maryland</i>	A Maryland demand-side management program for Pepco and DPL
<i>EPA</i>	United States Environmental Protection Agency
<i>ERCOT</i>	Electric Reliability Council of Texas
<i>ERISA</i>	Employee Retirement Income Security Act of 1974, as amended
<i>EROA</i>	Expected Rate of Return on Assets
<i>ESPP</i>	Employee Stock Purchase Plan
<i>FASB</i>	Financial Accounting Standards Board
<i>FERC</i>	Federal Energy Regulatory Commission
<i>FRCC</i>	Florida Reliability Coordinating Council
<i>FTC</i>	Federal Trade Commission
<i>GAAP</i>	Generally Accepted Accounting Principles in the United States
<i>GCR</i>	Gas Cost Rate
<i>GHG</i>	Greenhouse Gas
<i>GRT</i>	Gross Receipts Tax
<i>GSA</i>	Generation Supply Adjustment
<i>GWh</i>	Gigawatt hour
<i>HAP</i>	Hazardous air pollutants
<i>Health Care Reform Acts</i>	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
<i>HSR Act</i>	The Hart-Scott-Rodino Antitrust Improvements Act of 1976
<i>IBEW</i>	International Brotherhood of Electrical Workers
<i>ICC</i>	Illinois Commerce Commission
<i>ICE</i>	Intercontinental Exchange
<i>Illinois Act</i>	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
<i>Illinois EPA</i>	Illinois Environmental Protection Agency
<i>Illinois Settlement Legislation</i>	Legislation enacted in 2007 affecting electric utilities in Illinois
<i>Integrus</i>	Integrus Energy Services, Inc.
<i>IPA</i>	Illinois Power Agency
<i>IRC</i>	Internal Revenue Code
<i>IRS</i>	Internal Revenue Service
<i>ISO</i>	Independent System Operator
<i>ISO-NE</i>	ISO New England Inc.
<i>ISO-NY</i>	ISO New York
<i>kV</i>	Kilovolt
<i>kW</i>	Kilowatt
<i>kWh</i>	Kilowatt-hour
<i>LIBOR</i>	London Interbank Offered Rate
<i>LILO</i>	Lease-In, Lease-Out
<i>LLRW</i>	Low-Level Radioactive Waste
<i>LTIP</i>	Long-Term Incentive Plan
<i>MAPP</i>	Mid-Atlantic Power Pathway
<i>MATS</i>	U.S. EPA Mercury and Air Toxics Rule
<i>MBR</i>	Market Based Rates Incentive

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<i>MDE</i>	Maryland Department of the Environment
<i>MDPSC</i>	Maryland Public Service Commission
<i>MGP</i>	Manufactured Gas Plant
<i>MISO</i>	Midcontinent Independent System Operator, Inc.
<i>mmcf</i>	Million Cubic Feet
<i>Moody's</i>	Moody's Investor Service
<i>MOPR</i>	Minimum Offer Price Rule
<i>MRV</i>	Market-Related Value
<i>MW</i>	Megawatt
<i>MWh</i>	Megawatt hour
<i>NAAQS</i>	National Ambient Air Quality Standards
<i>n.m.</i>	not meaningful
<i>NAV</i>	Net Asset Value
<i>NDT</i>	Nuclear Decommissioning Trust
<i>NEIL</i>	Nuclear Electric Insurance Limited
<i>NERC</i>	North American Electric Reliability Corporation
<i>NGS</i>	Natural Gas Supplier
<i>NJBPU</i>	New Jersey Board of Public Utilities
<i>NJDEP</i>	New Jersey Department of Environmental Protection
<i>Non-Regulatory Agreements Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
<i>NOSA</i>	Nuclear Operating Services Agreement
<i>NOV</i>	Notice of Violation
<i>NPDES</i>	National Pollutant Discharge Elimination System
<i>NRC</i>	Nuclear Regulatory Commission
<i>NSPS</i>	New Source Performance Standards
<i>NUGs</i>	Non-utility generators
<i>NWPA</i>	Nuclear Waste Policy Act of 1982
<i>NYMEX</i>	New York Mercantile Exchange
<i>OCI</i>	Other Comprehensive Income
<i>OIESO</i>	Ontario Independent Electricity System Operator
<i>OPC</i>	Office of People's Counsel
<i>OPEB</i>	Other Postretirement Employee Benefits
<i>PA DEP</i>	Pennsylvania Department of Environmental Protection
<i>PAPUC</i>	Pennsylvania Public Utility Commission
<i>PGC</i>	Purchased Gas Cost Clause
<i>PHI Retirement Plan</i>	PHI's noncontributory retirement plan
<i>PJM</i>	PJM Interconnection, LLC
<i>POLR</i>	Provider of Last Resort
<i>POR</i>	Purchase of Receivables
<i>PPA</i>	Power Purchase Agreement
<i>Price-Anderson Act</i>	Price-Anderson Nuclear Industries Indemnity Act of 1957
<i>Preferred Stock</i>	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value \$0.01 per share
<i>PRP</i>	Potentially Responsible Parties
<i>PSEG</i>	Public Service Enterprise Group Incorporated
<i>PURTA</i>	Pennsylvania Public Realty Tax Act
<i>PV</i>	Photovoltaic

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**GLOSSARY OF TERMS AND ABBREVIATIONS**

**Other Terms and Abbreviations**

<i>RCRA</i>	Resource Conservation and Recovery Act of 1976, as amended
<i>REC</i>	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
<i>Regulatory Agreement Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
<i>RES</i>	Retail Electric Suppliers
<i>RFP</i>	Request for Proposal
<i>Rider</i>	Reconcilable Surcharge Recovery Mechanism
<i>RGGI</i>	Regional Greenhouse Gas Initiative
<i>RMC</i>	Risk Management Committee
<i>ROE</i>	Return on equity
<i>RPM</i>	PJM Reliability Pricing Model
<i>RPS</i>	Renewable Energy Portfolio Standards
<i>RTEP</i>	Regional Transmission Expansion Plan
<i>RTO</i>	Regional Transmission Organization
<i>S&amp;P</i>	Standard & Poor's Ratings Services
<i>SEC</i>	United States Securities and Exchange Commission
<i>Senate Bill 1</i>	Maryland Senate Bill 1
<i>SERC</i>	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
<i>SERP</i>	Supplemental Employee Retirement Plan
<i>SGIG</i>	Smart Grid Investment Grant
<i>SGIP</i>	Smart Grid Initiative Program
<i>SILO</i>	Sale-In, Lease-Out
<i>SMPIP</i>	Smart Meter Procurement and Installation Plan
<i>SNF</i>	Spent Nuclear Fuel
<i>SOCAs</i>	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
<i>SOS</i>	Standard Offer Service
<i>SPP</i>	Southwest Power Pool
<i>Tax Relief Act of 2010</i>	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
<i>Transition Bond Charge</i>	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
<i>Transition Bonds</i>	Transition Bonds issued by ACE Funding
<i>Upstream</i>	Natural gas exploration and production activities
<i>VIE</i>	Variable Interest Entity
<i>WECC</i>	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 I, 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](http://www.sec.gov) and the Registrants' websites at [www.exeloncorp.com](http://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**

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions, except per share data)</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Operating revenues</b>		
Competitive businesses revenues	\$ 4,473	\$ 5,632
Rate-regulated utility revenues	3,100	3,198
Total operating revenues	7,573	8,830
<b>Operating expenses</b>		
Competitive businesses purchased power and fuel	2,440	3,426
Rate-regulated utility purchased power and fuel	814	1,044
Operating and maintenance	2,835	2,081
Depreciation and amortization	685	610
Taxes other than income	325	304
Total operating expenses	7,099	7,465
<b>Gain on sales of assets</b>	9	1
<b>Operating income</b>	483	1,366
<b>Other income and (deductions)</b>		
Interest expense, net	(277)	(335)
Interest expense to affiliates, net	(10)	(10)
Other, net	114	80
Total other income and (deductions)	(173)	(265)
<b>Income before income taxes</b>	310	1,101
<b>Income taxes</b>	184	363
<b>Equity in losses of unconsolidated affiliates</b>	(3)	
<b>Net income</b>	123	738
<b>Net (loss) income attributable to noncontrolling interest and preference stock dividends</b>	(50)	45
<b>Net income attributable to common shareholders</b>	\$ 173	\$ 693
<b>Comprehensive income, net of income taxes</b>		
Net income	\$ 123	\$ 738
<b>Other comprehensive income (loss), net of income taxes</b>		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	(12)	(11)
Actuarial loss reclassified to periodic benefit cost	46	54
Pension and non-pension postretirement benefit plan valuation adjustment	(1)	(26)
Unrealized (loss) gain on cash flow hedges	(7)	6
Unrealized loss on equity investments	(3)	

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Unrealized gain (loss) on foreign currency translation	6	(12)
Unrealized loss on marketable securities	(1)	
Other comprehensive income	28	11
<b>Comprehensive income</b>	<b>\$ 151</b>	<b>\$ 749</b>
<b>Average shares of common stock outstanding:</b>		
Basic	923	862
Diluted	925	867
<b>Earnings per average common share:</b>		
Basic	\$ 0.19	\$ 0.80
Diluted	\$ 0.19	\$ 0.80
<b>Dividends per common share</b>	<b>\$ 0.31</b>	<b>\$ 0.31</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2016</b>	<b>March 31, 2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 123	\$ 738
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	1,063	948
Impairment of long-lived assets	119	
Gain on sales of assets	(9)	(1)
Deferred income taxes and amortization of investment tax credits	127	129
Net fair value changes related to derivatives	(107)	(91)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(55)	(47)
Other non-cash operating activities	804	344
Changes in assets and liabilities:		
Accounts receivable	117	(270)
Inventories	142	291
Accounts payable and accrued expenses	(571)	(468)
Option premiums received, net	17	5
Collateral received, net	206	257
Income taxes	47	174
Pension and non-pension postretirement benefit contributions	(239)	(269)
Other assets and liabilities	(311)	(250)
Net cash flows provided by operating activities	1,473	1,490
<b>Cash flows from investing activities</b>		
Capital expenditures	(2,202)	(1,784)
Proceeds from nuclear decommissioning trust fund sales	2,240	1,681
Investment in nuclear decommissioning trust funds	(2,297)	(1,747)
Acquisition of businesses, net of cash acquired	(6,645)	(15)
Proceeds from sale of long-lived assets		142
Proceeds from termination of direct financing lease investment	360	
Change in restricted cash	(2)	(26)
Other investing activities	(2)	(2)
Net cash flows used in investing activities	(8,548)	(1,751)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	1,647	(141)
Proceeds from short-term borrowings with maturities greater than 90 days	123	
Issuance of long-term debt	151	1,206
Retirement of long-term debt	(116)	(580)
Dividends paid on common stock	(287)	(269)
Proceeds from employee stock plans	9	8
Other financing activities	6	(16)
Net cash flows provided by financing activities	1,533	208



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Decrease in cash and cash equivalents	(5,542)	(53)
Cash and cash equivalents at beginning of period	6,502	1,878
Cash and cash equivalents at end of period	\$ 960	\$ 1,825

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 960	\$ 6,502
Restricted cash and cash equivalents	218	205
Accounts receivable, net		
Customer	3,594	3,187
Other	1,138	912
Mark-to-market derivative assets	1,185	1,365
Unamortized energy contract assets	85	86
Inventories, net		
Fossil fuel and emission allowances	285	462
Materials and supplies	1,229	1,104
Regulatory assets	1,584	759
Other	1,086	752
<b>Total current assets</b>	<b>11,364</b>	<b>15,334</b>
<b>Property, plant and equipment, net</b>	<b>69,406</b>	<b>57,439</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	10,407	6,065
Nuclear decommissioning trust funds	10,526	10,342
Investments	455	639
Goodwill	6,688	2,672
Mark-to-market derivative assets	841	758
Unamortized energy contracts assets	474	484
Pledged assets for Zion Station decommissioning	183	206
Other	1,398	1,445
<b>Total deferred debits and other assets</b>	<b>30,972</b>	<b>22,611</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 111,742</b>	<b>\$ 95,384</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 3,640	\$ 533
Long-term debt due within one year	2,058	1,500
Accounts payable	2,874	2,883
Accrued expenses	2,260	2,376
Payables to affiliates	8	8
Regulatory liabilities	512	369
Mark-to-market derivative liabilities	203	205
Unamortized energy contract liabilities	582	100
Renewable energy credit obligation	308	302
PHI merger related obligation	317	
Other	1,008	842
Total current liabilities	13,770	9,118
<b>Long-term debt</b>		
	29,314	23,645
<b>Long-term debt to financing trusts</b>		
	641	641
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	17,474	13,776
Asset retirement obligations	8,755	8,585
Pension obligations	3,771	3,385
Non-pension postretirement benefit obligations	1,902	1,618
Spent nuclear fuel obligation	1,022	1,021
Regulatory liabilities	4,378	4,201
Mark-to-market derivative liabilities	408	374
Unamortized energy contract liabilities	1,144	117
Payable for Zion Station decommissioning	72	90
Other	1,886	1,491
Total deferred credits and other liabilities	40,812	34,658
Total liabilities <sup>(a)</sup>	84,537	68,062
<b>Commitments and contingencies</b>		
<b>Contingently redeemable noncontrolling interest</b>		
	19	28
<b>Shareholders equity</b>		
Common stock (No par value, 2000 shares authorized, 922 shares and 920 shares outstanding at March 31, 2016 and December 31, 2015, respectively)	18,686	18,676
Treasury stock, at cost (35 shares at March 31, 2016 and December 31, 2015, respectively)	(2,327)	(2,327)
Retained earnings	11,954	12,068
Accumulated other comprehensive loss, net	(2,596)	(2,624)
Total shareholders equity	25,717	25,793
BGE preference stock not subject to mandatory redemption	193	193

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Noncontrolling interest	1,276	1,308
Total equity	27,186	27,294
<b>Total liabilities and shareholders equity</b>	<b>\$ 111,742</b>	<b>\$ 95,384</b>

- (a) Exelon's consolidated assets include \$8,310 million and \$8,268 million at March 31, 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 \$3,421 million and \$3,264 million at March 31, 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 Interest	Preference Stock	Total Shareholders' Equity
<b>Balance, December 31, 2015</b>	954,668	\$ 18,676	\$ (2,327)	\$ 12,068	\$ (2,624)	\$ 1,308	\$ 193	\$ 27,294
Net income				173		(53)	3	123
Long-term incentive plan activity	1,783	17						17
Employee stock purchase plan issuances	351	9						9
Tax benefit on stock compensation		(16)						(16)
Changes in equity of noncontrolling interest						2		2
Adjustment of contingently redeemable noncontrolling interest due to release of contingency						19		19
Common stock dividends				(287)				(287)
Preference stock dividends							(3)	(3)
Other comprehensive income, net of income taxes					28			28
<b>Balance, March 31, 2016</b>	956,802	\$ 18,686	\$ (2,327)	\$ 11,954	\$ (2,596)	\$ 1,276	\$ 193	\$ 27,186

See the Combined Notes to Consolidated Financial Statements

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**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2016	2015
<b>Operating revenues</b>		
Operating revenues	\$ 4,471	\$ 5,629
Operating revenues from affiliates	268	211
Total operating revenues	4,739	5,840
<b>Operating expenses</b>		
Purchased power and fuel	2,440	3,426
Purchased power and fuel from affiliates	2	7
Operating and maintenance	1,296	1,162
Operating and maintenance from affiliates	171	149
Depreciation and amortization	289	254
Taxes other than income	126	122
Total operating expenses	4,324	5,120
<b>Loss on sales of assets</b>		(1)
<b>Operating income</b>	415	719
<b>Other income and (deductions)</b>		
Interest expense, net	(87)	(90)
Interest expense to affiliates	(10)	(12)
Other, net	93	94
Total other income and (deductions)	(4)	(8)
<b>Income before income taxes</b>	411	711
<b>Income taxes</b>	151	226
<b>Equity in losses of unconsolidated affiliates</b>	(3)	
<b>Net income</b>	257	485
<b>Net (loss) income attributable to noncontrolling interests</b>	(53)	42
<b>Net income attributable to membership interest</b>	\$ 310	\$ 443
<b>Comprehensive income, net of income taxes</b>		
Net income	\$ 257	\$ 485
<b>Other comprehensive income (loss), net of income taxes</b>		
Unrealized loss on cash flow hedges	(5)	(5)
Unrealized loss on equity investments	(2)	
Unrealized gain (loss) on foreign currency translation	6	(12)
Other comprehensive income (loss)	(1)	(17)

<b>Comprehensive income</b>	\$ 256	\$ 468
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**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 257	\$ 485
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	667	591
Impairment of long-lived assets	119	
Loss on sales of assets		1
Deferred income taxes and amortization of investment tax credits	68	89
Net fair value changes related to derivatives	(106)	(165)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(55)	(47)
Other non-cash operating activities	51	45
Changes in assets and liabilities:		
Accounts receivable	173	24
Receivables from and payables to affiliates, net	(17)	(10)
Inventories	93	228
Accounts payable and accrued expenses	(363)	(254)
Option premiums received, net	17	5
Collateral received, net	198	288
Income taxes	(60)	(104)
Pension and non-pension postretirement benefit contributions	(112)	(107)
Other assets and liabilities	(148)	(232)
<b>Net cash flows provided by operating activities</b>	<b>782</b>	<b>837</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(1,125)	(937)
Proceeds from nuclear decommissioning trust fund sales	2,240	1,681
Investment in nuclear decommissioning trust funds	(2,297)	(1,747)
Acquisition of businesses	(1)	(15)
Proceeds from sale of long-lived assets		142
Change in restricted cash	4	(21)
Other investing activities	(25)	(2)
<b>Net cash flows used in investing activities</b>	<b>(1,204)</b>	<b>(899)</b>
<b>Cash flows from financing activities</b>		
Change in short-term borrowings	1,377	(1)
Proceeds from short-term borrowings with maturities greater than 90 days	123	
Issuance of long-term debt	151	806
Retirement of long-term debt	(94)	(18)
Retirement of long-term debt to affiliate		(550)
Changes in Exelon intercompany money pool	(1,183)	936
Distribution to member	(55)	(1,356)
Contribution from member	44	
Other financing activities	5	(3)



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Net cash flows provided by (used in) financing activities	368	(186)
<b>Decrease in cash and cash equivalents</b>	(54)	(248)
<b>Cash and cash equivalents at beginning of period</b>	431	780
<b>Cash and cash equivalents at end of period</b>	\$ 377	\$ 532

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**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 377	\$ 431
Restricted cash and cash equivalents	119	123
Accounts receivable, net		
Customer	1,963	2,095
Other	434	360
Mark-to-market derivative assets	1,185	1,365
Receivables from affiliates	154	83
Unamortized energy contract assets	85	86
Inventories, net		
Fossil fuel and emission allowances	251	384
Materials and supplies	884	880
Other	719	535
<b>Total current assets</b>	<b>6,171</b>	<b>6,342</b>
<b>Property, plant and equipment, net</b>	<b>26,166</b>	<b>25,843</b>
<b>Deferred debits and other assets</b>		
Nuclear decommissioning trust funds	10,526	10,342
Investments	250	210
Goodwill	47	47
Mark-to-market derivative assets	799	733
Prepaid pension asset	1,725	1,689
Pledged assets for Zion Station decommissioning	183	206
Unamortized energy contract assets	473	484
Deferred income taxes	12	6
Other	650	627
<b>Total deferred debits and other assets</b>	<b>14,665</b>	<b>14,344</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 47,002</b>	<b>\$ 46,529</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 1,529	\$ 29
Long-term debt due within one year	177	90
Accounts payable	1,290	1,583
Accrued expenses	673	935
Payables to affiliates	140	104
Borrowings from Exelon intercompany money pool	63	1,252
Mark-to-market derivative liabilities	177	182
Unamortized energy contract liabilities	85	100
Renewable energy credit obligation	308	302
Other	333	356
<b>Total current liabilities</b>	<b>4,775</b>	<b>4,933</b>
<b>Long-term debt</b>	<b>7,945</b>	<b>7,936</b>
<b>Long-term debt to affiliate</b>	<b>930</b>	<b>933</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	5,872	5,845
Asset retirement obligations	8,588	8,431
Non-pension postretirement benefit obligations	937	924
Spent nuclear fuel obligation	1,022	1,021
Payables to affiliates	2,600	2,577
Mark-to-market derivative liabilities	166	150
Unamortized energy contract liabilities	106	117
Payable for Zion Station decommissioning	71	90
Other	637	602
<b>Total deferred credits and other liabilities</b>	<b>19,999</b>	<b>19,757</b>
<b>Total liabilities<sup>(a)</sup></b>	<b>33,649</b>	<b>33,559</b>
<b>Commitments and contingencies</b>		
<b>Contingently redeemable noncontrolling interests</b>	<b>19</b>	<b>28</b>
<b>Equity</b>		
Member s equity		
Membership interest	9,167	8,997
Undistributed earnings	2,956	2,701
Accumulated other comprehensive loss, net	(64)	(63)
<b>Total member s equity</b>	<b>12,059</b>	<b>11,635</b>
Noncontrolling interest	1,275	1,307
<b>Total equity</b>	<b>13,334</b>	<b>12,942</b>

<b>Total liabilities and equity</b>	\$ 47,002	\$ 46,529
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- (a) Generation s consolidated assets include \$8,190 million and \$8,235 million at March 31, 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 \$3,094 million and \$3,135 million at March 31, 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)

(In millions)	Member's Equity				Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	
<b>Balance, December 31, 2015</b>	\$ 8,997	\$ 2,701	\$ (63)	\$ 1,307	\$ 12,942
Net income (loss)		310		(53)	257
Acquisition of non-controlling interest				2	2
Adjustment of contingently redeemable noncontrolling interest due to release of contingency				19	19
Contribution from member	170				170
Distribution to member		(55)			(55)
Other comprehensive loss, net of income taxes			(1)		(1)
<b>Balance, March 31, 2016</b>	\$ 9,167	\$ 2,956	\$ (64)	\$ 1,275	\$ 13,334

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**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2016	2015
<b>Operating revenues</b>		
Electric operating revenues	\$ 1,244	\$ 1,184
Operating revenues from affiliates	5	1
Total operating revenues	1,249	1,185
<b>Operating expenses</b>		
Purchased power	343	318
Purchased power from affiliate	5	9
Operating and maintenance	305	333
Operating and maintenance from affiliate	63	45
Depreciation and amortization	189	175
Taxes other than income	75	75
Total operating expenses	980	955
Gain on sale of assets	5	
<b>Operating income</b>	274	230
<b>Other income and (deductions)</b>		
Interest expense, net	(83)	(81)
Interest expense to affiliates	(3)	(3)
Other, net	4	3
Total other income and (deductions)	(82)	(81)
<b>Income before income taxes</b>	192	149
<b>Income taxes</b>	77	59
<b>Net income</b>	\$ 115	\$ 90
<b>Comprehensive income</b>	\$ 115	\$ 90

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**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 115	\$ 90
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	189	175
Deferred income taxes and amortization of investment tax credits	70	35
Other non-cash operating activities	32	126
Changes in assets and liabilities:		
Accounts receivable	69	(38)
Receivables from and payables to affiliates, net		(2)
Inventories	7	(10)
Accounts payable and accrued expenses	(207)	(121)
Collateral received (posted), net	7	(5)
Income taxes	20	131
Pension and non-pension postretirement benefit contributions	(32)	(121)
Other assets and liabilities	14	(9)
Net cash flows provided by operating activities	284	251
<b>Cash flows from investing activities</b>		
Capital expenditures	(639)	(530)
Other investing activities	13	7
Net cash flows used in investing activities	(626)	(523)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	349	(21)
Issuance of long-term debt		400
Contributions from parent	39	14
Dividends paid on common stock	(91)	(75)
Other financing activities	(1)	(4)
Net cash flows provided by financing activities	296	314
<b>(Decrease) Increase in cash and cash equivalents</b>	<b>(46)</b>	<b>42</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>67</b>	<b>66</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 21</b>	<b>\$ 108</b>

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**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 21	\$ 67
Restricted cash	2	2
Accounts receivable, net		
Customer	479	533
Other	221	272
Receivables from affiliates	202	199
Inventories, net	157	164
Regulatory assets	239	218
Other	51	63
Total current assets	1,372	1,518
<b>Property, plant and equipment, net</b>	<b>17,971</b>	<b>17,502</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	925	895
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,182	2,172
Prepaid pension asset	1,476	1,490
Other	330	324
Total deferred debits and other assets	7,544	7,512
<b>Total assets</b>	<b>\$ 26,887</b>	<b>\$ 26,532</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 643	\$ 294
Long-term debt due within one year	665	665
Accounts payable	645	660
Accrued expenses	539	706
Payables to affiliates	64	62
Customer deposits	130	131
Regulatory liabilities	150	155
Mark-to-market derivative liability	26	23
Other	76	70
Total current liabilities	2,938	2,766
<b>Long-term debt</b>		
	5,845	5,844
<b>Long-term debt to financing trust</b>		
	205	205
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	4,985	4,914
Asset retirement obligations	113	111
Non-pension postretirement benefits obligations	254	259
Regulatory liabilities	3,489	3,459
Mark-to-market derivative liability	239	224
Other	512	507
Total deferred credits and other liabilities	9,592	9,474
Total liabilities	18,580	18,289
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock	1,588	1,588
Other paid-in capital	5,717	5,677
Retained earnings	1,002	978
Total shareholders equity	8,307	8,243
<b>Total liabilities and shareholders equity</b>	<b>\$ 26,887</b>	<b>\$ 26,532</b>

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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
<b>Balance, December 31, 2015</b>	\$ 1,588	\$ 5,677	\$ (1,639)	\$ 2,617	\$ 8,243
Net income			115		115
Appropriation of retained earnings for future dividends			(115)	115	
Common stock dividends				(91)	(91)
Contribution from parent		39			39
Parent tax matter indemnification		1			1
<b>Balance, March 31, 2016</b>	\$ 1,588	\$ 5,717	\$ (1,639)	\$ 2,641	\$ 8,307

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Operating revenues</b>		
Electric operating revenues	\$ 643	\$ 677
Natural gas operating revenues	197	308
Operating revenues from affiliates	1	
<b>Total operating revenues</b>	<b>841</b>	<b>985</b>
<b>Operating expenses</b>		
Purchased power	166	216
Purchased fuel	77	160
Purchased power from affiliate	78	62
Operating and maintenance	177	197
Operating and maintenance from affiliates	38	25
Depreciation and amortization	67	62
Taxes other than income	42	41
<b>Total operating expenses</b>	<b>645</b>	<b>763</b>
<b>Gain on sales of assets</b>		<b>1</b>
<b>Operating income</b>	<b>196</b>	<b>223</b>
<b>Other income and (deductions)</b>		
Interest expense, net	(28)	(25)
Interest expense to affiliates	(3)	(3)
Other, net	2	2
<b>Total other income and (deductions)</b>	<b>(29)</b>	<b>(26)</b>
<b>Income before income taxes</b>	<b>167</b>	<b>197</b>
<b>Income taxes</b>	<b>43</b>	<b>58</b>
<b>Net income attributable to common shareholder</b>	<b>\$ 124</b>	<b>\$ 139</b>
<b>Comprehensive income</b>	<b>\$ 124</b>	<b>\$ 139</b>

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**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 124	\$ 139
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	67	62
Deferred income taxes and amortization of investment tax credits	23	5
Other non-cash operating activities	24	44
Changes in assets and liabilities:		
Accounts receivable	(51)	(115)
Receivables from and payables to affiliates, net	4	5
Inventories	24	34
Accounts payable and accrued expenses	18	(1)
Income taxes	29	67
Pension and non-pension postretirement benefit contributions	(29)	(12)
Other assets and liabilities	(95)	(70)
<b>Net cash flows provided by operating activities</b>	<b>138</b>	<b>158</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(195)	(148)
Changes in Exelon intercompany money pool	(160)	
Other investing activities	4	4
<b>Net cash flows used in investing activities</b>	<b>(351)</b>	<b>(144)</b>
<b>Cash flows from financing activities</b>		
Changes in Exelon intercompany money pool		65
Dividends paid on common stock	(69)	(70)
Other financing activities		(1)
<b>Net cash flows used in financing activities</b>	<b>(69)</b>	<b>(6)</b>
<b>Increase (decrease) in cash and cash equivalents</b>	<b>(282)</b>	<b>8</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>295</b>	<b>30</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 13</b>	<b>\$ 38</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 13	\$ 295
Restricted cash and cash equivalents	3	3
Accounts receivable, net		
Customer	288	258
Other	124	146
Receivables from affiliates	5	2
Receivable from Exelon intercompany pool	160	
Inventories, net		
Fossil fuel	18	43
Materials and supplies	27	26
Prepaid utility taxes	110	11
Regulatory assets	42	34
Other	26	24
Total current assets	816	842
<b>Property, plant and equipment, net</b>	<b>7,209</b>	<b>7,141</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	1,605	1,583
Investments	27	28
Receivable from affiliates	417	405
Prepaid pension asset	368	347
Other	20	21
Total deferred debits and other assets	2,437	2,384
<b>Total assets</b>	<b>\$ 10,462</b>	<b>\$ 10,367</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Long-term debt due within one year	\$ 300	\$ 300
Accounts payable	261	281
Accrued expenses	84	109
Payables to affiliates	62	55
Customer deposits	59	58
Regulatory liabilities	134	112
Other	33	29
Total current liabilities	933	944
<b>Long-term debt</b>		
Long-term debt to financing trusts	2,281	2,280
Deferred credits and other liabilities	184	184
Deferred income taxes and unamortized investment tax credits	2,849	2,792
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	287
Regulatory liabilities	521	527
Other	88	90
Total deferred credits and other liabilities	3,773	3,723
Total liabilities	7,171	7,131
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	2,455	2,455
Retained earnings	835	780
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,291	3,236
<b>Total liabilities and shareholder s equity</b>	<b>\$ 10,462</b>	<b>\$ 10,367</b>

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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
<b>Balance, December 31, 2015</b>	\$ 2,455	\$ 780	\$ 1	\$ 3,236
Net income		124		124
Common stock dividends		(69)		(69)
<b>Balance, March 31, 2016</b>	\$ 2,455	\$ 835	\$ 1	\$ 3,291

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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 March 31,	
	2016	2015
<b>Operating revenues</b>		
Electric operating revenues	\$ 678	\$ 714
Natural gas operating revenues	246	315
Operating revenues from affiliates	5	7
<b>Total operating revenues</b>	<b>929</b>	<b>1,036</b>
<b>Operating expenses</b>		
Purchased power	127	208
Purchased fuel	75	142
Purchased power from affiliate	171	137
Operating and maintenance	168	156
Operating and maintenance from affiliates	34	26
Depreciation and amortization	109	106
Taxes other than income	58	57
<b>Total operating expenses</b>	<b>742</b>	<b>832</b>
<b>Operating income</b>	<b>187</b>	<b>204</b>
<b>Other income and (deductions)</b>		
Interest expense, net	(20)	(21)
Interest expense to affiliates	(4)	(4)
Other, net	4	4
<b>Total other income and (deductions)</b>	<b>(20)</b>	<b>(21)</b>
<b>Income before income taxes</b>	<b>167</b>	<b>183</b>
<b>Income taxes</b>	<b>66</b>	<b>74</b>
<b>Net income</b>	<b>101</b>	<b>109</b>
<b>Preference stock dividends</b>	<b>3</b>	<b>3</b>
<b>Net income attributable to common shareholder</b>	<b>\$ 98</b>	<b>\$ 106</b>
<b>Comprehensive income</b>	<b>\$ 101</b>	<b>\$ 109</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2016</b>	<b>March 31, 2015</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 101	\$ 109
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	109	106
Deferred income taxes and amortization of investment tax credits	26	33
Other non-cash operating activities	44	64
Changes in assets and liabilities:		
Accounts receivable	(44)	(141)
Receivables from and payables to affiliates, net	7	(8)
Inventories	17	38
Accounts payable and accrued expenses	3	(14)
Collateral received (posted), net		(27)
Income taxes	78	26
Pension and non-pension postretirement benefit contributions	(38)	(4)
Other assets and liabilities	(30)	99
Net cash flows provided by operating activities	273	281
<b>Cash flows from investing activities</b>		
Capital expenditures	(176)	(136)
Change in restricted cash	(20)	2
Other investing activities	5	2
Net cash flows used in investing activities	(191)	(132)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(60)	(120)
Dividends paid on preference stock	(3)	(3)
Dividends paid on common stock	(45)	(36)
Contributions from parent	21	
Other financing activities	1	(13)
Net cash flows used in financing activities	(86)	(172)
<b>Decrease in cash and cash equivalents</b>	<b>(4)</b>	<b>(23)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>9</b>	<b>64</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 5</b>	<b>\$ 41</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 5	\$ 9
Restricted cash and cash equivalents	44	24
Accounts receivable, net		
Customer	328	300
Other	77	112
Inventories, net		
Gas held in storage	13	36
Materials and supplies	39	33
Prepaid utility taxes	31	61
Regulatory assets	266	267
Other	16	3
Total current assets	819	845
<b>Property, plant and equipment, net</b>	<b>6,684</b>	<b>6,597</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	499	514
Investments	12	12
Prepaid pension asset	337	319
Other	10	8
Total deferred debits and other assets	858	853
<b>Total assets<sup>(a)</sup></b>	<b>\$ 8,361</b>	<b>\$ 8,295</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 150	\$ 210
Long-term debt due within one year	378	378
Accounts payable	206	209
Accrued expenses	151	110
Payables to affiliates	59	52
Customer deposits	105	102
Regulatory liabilities	61	38
Other	28	35
<b>Total current liabilities</b>	<b>1,138</b>	<b>1,134</b>
<b>Long-term debt</b>	<b>1,481</b>	<b>1,480</b>
<b>Long-term debt to financing trust</b>	<b>252</b>	<b>252</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	2,104	2,081
Asset retirement obligations	15	17
Non-pension postretirement benefits obligations	205	209
Regulatory liabilities	151	184
Other	71	61
<b>Total deferred credits and other liabilities</b>	<b>2,546</b>	<b>2,552</b>
<b>Total liabilities<sup>(a)</sup></b>	<b>5,417</b>	<b>5,418</b>
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock	1,381	1,367
Retained earnings	1,373	1,320
<b>Total shareholders equity</b>	<b>2,754</b>	<b>2,687</b>
Preference stock not subject to mandatory redemption	190	190
<b>Total equity</b>	<b>2,944</b>	<b>2,877</b>
<b>Total liabilities and shareholders equity</b>	<b>\$ 8,361</b>	<b>\$ 8,295</b>

(a) BGE's consolidated assets include \$47 million and \$26 million at March 31, 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 \$41 million and \$41 million at March 31, 2016 and December 31, 2015, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to

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BGE. See Note 3 Variable Interest Entities.

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**Table of Contents****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
<b>Balance, December 31, 2015</b>	\$ 1,367	\$ 1,320	\$ 2,687	\$ 190	\$ 2,877
Net income		101	101		101
Preference stock dividends		(3)	(3)		(3)
Common stock dividends		(45)	(45)		(45)
Distribution to parent	(7)		(7)		(7)
Contribution from parent	21		21		21
<b>Balance, March 31, 2016</b>	\$ 1,381	\$ 1,373	\$ 2,754	\$ 190	\$ 2,944

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions)</b>	<i>Successor</i> <b>March 24 to March 31,</b>	<i>Predecessor</i> <b>January 1 to March 23,</b>	<i>Predecessor</i> <b>Three Months Ended March 31,</b>
	<b>2016</b>	<b>2016</b>	<b>2015</b>
<b>Operating revenues</b>			
Electric operating revenues	\$ 90	\$ 1,096	\$ 1,268
Natural gas operating revenues	3	57	86
Operating revenues from affiliates	12		
<b>Total operating revenues</b>	<b>105</b>	<b>1,153</b>	<b>1,354</b>
<b>Operating expenses</b>			
Purchased power	26	471	588
Purchased fuel	1	26	51
Purchased power and fuel from affiliates	11		
Operating and maintenance	447	294	300
Operating and maintenance from affiliates	2		
Depreciation and amortization	14	152	155
Taxes other than income	15	105	118
<b>Total operating expenses</b>	<b>516</b>	<b>1,048</b>	<b>1,212</b>
<b>Operating (loss) income</b>	<b>(411)</b>	<b>105</b>	<b>142</b>
<b>Other income and (deductions)</b>			
Interest expense, net	(6)	(65)	(68)
Other, net	2	(4)	9
<b>Total other income and (deductions)</b>	<b>(4)</b>	<b>(69)</b>	<b>(59)</b>
<b>(Loss) Income before income taxes</b>	<b>(415)</b>	<b>36</b>	<b>83</b>
<b>Income taxes</b>	<b>(106)</b>	<b>17</b>	<b>30</b>
<b>Net (loss) income attributable to membership interest/common shareholders</b>	<b>\$ (309)</b>	<b>\$ 19</b>	<b>\$ 53</b>
<b>Comprehensive (loss) income, net of income taxes</b>			
Net (loss) income	\$ (309)	\$ 19	\$ 53
<b>Other comprehensive income, net of income taxes</b>			
Pension and non-pension postretirement benefit plans:			
Actuarial loss reclassified to periodic cost		1	1
Other comprehensive income		1	1
<b>Comprehensive (loss) income</b>	<b>\$ (309)</b>	<b>\$ 20</b>	<b>\$ 54</b>

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See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<i>Successor</i> <b>March 24 to March 31, 2016</b>	<b>January 1 to March 23, 2016</b>	<i>Predecessor</i> <b>Three Months Ended March 31, 2015</b>
<b>Cash flows from operating activities</b>			
Net (loss) income	\$ (309)	\$ 19	\$ 53
Adjustments to reconcile net (loss) income to net cash from operating activities:			
Depreciation, amortization and accretion	14	152	155
Deferred income taxes and amortization of investment tax credits	(112)	19	49
Net fair value changes related to derivatives		18	
Other non-cash operating activities	410	46	57
Changes in assets and liabilities:			
Accounts receivable	16	(28)	(214)
Receivables from and payables to affiliates, net	46		
Inventories		(4)	(3)
Accounts payable and accrued expenses	(4)	42	43
Collateral received, net		1	
Income taxes	7	12	(3)
Pension and non-pension postretirement benefit contributions		(4)	(5)
Other assets and liabilities	(25)	(9)	25
<b>Net cash flows provided by operating activities</b>	<b>43</b>	<b>264</b>	<b>157</b>
<b>Cash flows from investing activities</b>			
Capital expenditures	(29)	(273)	(246)
Changes in restricted cash	(1)	3	9
Purchases of investments	(2)	(68)	
Other investing activities	2	(5)	2
<b>Net cash flows used in investing activities</b>	<b>(30)</b>	<b>(343)</b>	<b>(235)</b>
<b>Cash flows from financing activities</b>			
Changes in short-term borrowings	(20)	(121)	74
Proceeds from short-term borrowings with maturities greater than 90 days		500	
Issuance of long-term debt			208
Retirement of long-term debt		(11)	(22)
Issuance of preferred stock			18
Dividends paid on common stock			(68)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation		2	8
Distribution to member	(108)		
Change in Exelon intercompany money pool	(53)		
Other financing activities		2	(13)
<b>Net cash flows provided by financing activities</b>	<b>(181)</b>	<b>372</b>	<b>205</b>



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<b>(Decrease) Increase in cash and cash equivalents</b>	(168)	293	127
<b>Cash and cash equivalents at beginning of period</b>	319	26	15
<b>Cash and cash equivalents at end of period</b>	\$ 151	\$ 319	\$ 142

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**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	<i>Successor</i> March 31, 2016 (Unaudited)	<i>Predecessor</i> December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 151	\$ 26
Restricted cash and cash equivalents	12	14
Accounts receivable, net		
Customer	536	581
Other	284	316
Mark-to-market derivative asset		18
Receivable from affiliates	16	
Inventories, net		
Gas held in storage	4	9
Materials and supplies	122	122
Regulatory assets	801	305
Other	75	81
<b>Total current assets</b>	<b>2,001</b>	<b>1,472</b>
<b>Property, plant and equipment, net</b>	<b>10,980</b>	<b>10,864</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	3,202	2,277
Investments	131	80
Goodwill	4,016	1,406
Long-term note receivable	4	4
Prepaid pension asset	517	
Unamortized energy contract assets	1	
Deferred income taxes	23	14
Other	57	67
<b>Total deferred debits and other assets</b>	<b>7,951</b>	<b>3,848</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 20,932</b>	<b>\$ 16,184</b>

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**Table of Contents****PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	<i>Successor</i> <b>March 31, 2016</b> <i>(Unaudited)</i>	<i>Predecessor</i> <b>December 31, 2015</b>
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 1,317	\$ 958
Long-term debt due within one year	476	456
Accounts payable	348	404
Accrued expenses	327	263
Payables to affiliates	66	
Unamortized energy contract liabilities	497	
Customer deposits	121	107
Merger related obligation	235	
Regulatory liabilities	106	66
Other	51	70
<b>Total current liabilities</b>	<b>3,544</b>	<b>2,324</b>
<b>Long-term debt</b>	<b>5,656</b>	<b>4,823</b>
<b>Deferred credits and other liabilities</b>		
Regulatory liabilities	186	147
Deferred income taxes and unamortized investment tax credits	3,399	3,406
Asset retirement obligations	5	8
Pension obligations		466
Non-pension postretirement benefit obligations	143	215
Unamortized energy contract liabilities	1,038	
Other	289	199
<b>Total deferred credits and other liabilities</b>	<b>5,060</b>	<b>4,441</b>
<b>Total liabilities<sup>(a)</sup></b>	<b>14,260</b>	<b>11,588</b>
<b>Commitments and contingencies</b>		
<b>Preferred stock<sup>(b)</sup></b>		183
<b>Member s equity/Shareholders equity</b>		
Membership interest/Common stock <sup>(c)</sup>	6,981	3,832
Undistributed (losses)/Retained earnings	(309)	617
Accumulated other comprehensive loss, net		(36)
<b>Total member s equity/shareholders equity</b>	<b>6,672</b>	<b>4,413</b>
<b>Total liabilities and member s equity/shareholders equity</b>	<b>\$ 20,932</b>	<b>\$ 16,184</b>

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- (a) PHI's consolidated total assets include \$68 million and \$30 million at March 31, 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 \$200 million and \$172 million at March 31, 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, except shares)	Common Stock/ Membership Interest <sup>(a)</sup>	Retained Earnings/ Undistributed Losses	Accumulated Other Comprehensive Loss, net	Total Shareholders / Members Equity
<i>Predecessor</i>				
<b>Balance at December 31, 2015</b>	\$ 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
<b>Balance at March 23, 2016</b>	\$ 3,838	\$ 636	\$ (35)	\$ 4,439
<i>Successor</i>				
<b>Balance at March 24, 2016<sup>(b)</sup></b>	\$ 7,200	\$	\$	\$ 7,200
Net loss		(309)		(309)
Distribution to member	(235)			(235)
Distribution of net retirement benefit obligation to member	45			45
Assumption of member purchase liability <sup>(c)</sup>	(29)			(29)
<b>Balance at March 31, 2016</b>	\$ 6,981	\$ (309)	\$	\$ 6,672

(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) The total purchase price consideration for the PHI Merger included \$29 million for cash paid for PHI stock-based compensation awards. See Note 4 Mergers, Acquisitions and Dispositions for further information. The \$29 million of cash was paid by PHI.

See the Combined Notes to Consolidated Financial Statements

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**POTOMAC ELECTRIC POWER COMPANY**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2016	2015
<b>Operating revenues</b>		
Electric operating revenues	\$ 550	\$ 544
Operating revenues from affiliates	1	1
Total operating revenues	551	545
<b>Operating expenses</b>		
Purchased power	191	211
Purchased power and fuel from affiliates	6	
Operating and maintenance	288	112
Operating and maintenance from affiliates	2	1
Depreciation and amortization	75	62
Taxes other than income	94	96
Total operating expenses	656	482
<b>Operating (loss) income</b>	(105)	63
<b>Other income and (deductions)</b>		
Interest expense, net	(37)	(30)
Other, net	9	5
Total other income and (deductions)	(28)	(25)
<b>(Loss) Income before income taxes</b>	(133)	38
<b>Income taxes</b>	(25)	12
<b>Net (loss) income attributable to common shareholder</b>	\$ (108)	\$ 26
<b>Comprehensive (loss) income</b>	\$ (108)	\$ 26

See the Combined Notes to Financial Statements

**Table of Contents****POTOMAC ELECTRIC POWER COMPANY****STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net (loss) income	\$ (108)	\$ 26
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation and amortization	75	62
Deferred income taxes and amortization of investment tax credits	(31)	12
Other non-cash operating activities	153	23
Changes in assets and liabilities:		
Accounts receivable	(24)	(93)
Receivables from and payables to affiliates, net	55	21
Inventories	1	(6)
Accounts payable and accrued expenses	(4)	6
Income taxes	151	
Pension and non-pension postretirement benefit contributions	(1)	
Other assets and liabilities	(9)	(18)
<b>Net cash flows provided by operating activities</b>	<b>258</b>	<b>33</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(109)	(119)
Purchases of investments	(31)	
Changes in restricted cash	2	3
Other investing activities	2	3
<b>Net cash flows used in investing activities</b>	<b>(136)</b>	<b>(113)</b>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(64)	(104)
Issuance of long-term debt		208
Retirement of long-term debt		(12)
Dividends paid on common stock	(39)	
Contribution from parent		112
Other financing activities		(4)
<b>Net cash flows (used in) provided by financing activities</b>	<b>(103)</b>	<b>200</b>
<b>Increase in cash and cash equivalents</b>	<b>19</b>	<b>120</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>5</b>	<b>6</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 24</b>	<b>\$ 126</b>

See the Combined Notes to Financial Statements

**Table of Contents****POTOMAC ELECTRIC POWER COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 24	\$ 5
Restricted cash and cash equivalents		2
Accounts receivable, net		
Customer	240	230
Other	117	261
Inventories, net	65	67
Regulatory assets	133	140
Assets held for sale	4	
Other	22	21
Total current assets	605	726
<b>Property, plant and equipment, net</b>	<b>5,225</b>	<b>5,162</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	663	661
Investments	99	68
Prepaid pension asset	280	287
Other	5	4
Total deferred debits and other assets	1,047	1,020
<b>Total assets</b>	<b>\$ 6,877</b>	<b>\$ 6,908</b>

See the Combined Notes to Financial Statements



**Table of Contents****POTOMAC ELECTRIC POWER COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$	\$ 64
Long-term debt due within one year	11	11
Accounts payable	129	145
Accrued expenses	138	119
Payables to affiliates	85	30
Customer deposits	51	46
Regulatory liabilities	26	15
Merger related obligation	49	
Other	20	25
Total current liabilities	509	455
<b>Long-term debt</b>		
	2,341	2,340
<b>Deferred credits and other liabilities</b>		
Regulatory liabilities	29	29
Deferred income taxes and unamortized investment tax credits	1,695	1,723
Non-pension postretirement benefit obligations	49	49
Other	161	72
Total deferred credits and other liabilities	1,934	1,873
Total liabilities	4,784	4,668
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	1,122	1,122
Retained earnings	971	1,118
Total shareholder s equity	2,093	2,240
<b>Total liabilities and shareholder s equity</b>	<b>\$ 6,877</b>	<b>\$ 6,908</b>

See the Combined Notes to Financial Statements

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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
<b>Balance, December 31, 2015</b>	\$ 1,122	\$ 1,118	\$ 2,240
Net loss		(108)	(108)
Common stock dividends		(39)	(39)
<b>Balance, March 31, 2016</b>	\$ 1,122	\$ 971	\$ 2,093

See the Combined Notes to Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2016</b>	<b>March 31, 2015</b>
<b>Operating revenues</b>		
Electric operating revenues	\$ 301	\$ 333
Natural gas operating revenues	59	86
Operating revenues from affiliates	2	2
<b>Total operating revenues</b>	<b>362</b>	<b>421</b>
<b>Operating expenses</b>		
Purchased power	147	178
Purchased fuel	25	47
Purchased power from affiliate	4	
Operating and maintenance	204	81
Depreciation, amortization and accretion	39	39
Taxes other than income	15	13
<b>Total operating expenses</b>	<b>434</b>	<b>358</b>
<b>Operating (loss) income</b>	<b>(72)</b>	<b>63</b>
<b>Other income and (deductions)</b>		
Interest expense, net	(12)	(12)
Other, net	3	2
<b>Total other income and (deductions)</b>	<b>(9)</b>	<b>(10)</b>
<b>(Loss) Income before income taxes</b>	<b>(81)</b>	<b>53</b>
<b>Income taxes</b>	<b>(9)</b>	<b>21</b>
<b>Net (loss) income attributable to common shareholder</b>	<b>\$ (72)</b>	<b>\$ 32</b>
<b>Comprehensive (loss) income</b>	<b>\$ (72)</b>	<b>\$ 32</b>

See the Combined Notes to Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2016</b>	<b>March 31, 2015</b>
<b>Cash flows from operating activities</b>		
Net (loss) income	\$ (72)	\$ 32
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	39	39
Deferred income taxes and amortization of investment tax credits	(4)	21
Other non-cash operating activities	118	12
Changes in assets and liabilities:		
Accounts receivable	4	(82)
Receivables from and payables to affiliates, net	20	4
Inventories	1	5
Accounts payable and accrued expenses	(3)	12
Collateral received	1	
Income taxes	52	
Other assets and liabilities	(9)	14
<b>Net cash flows provided by operating activities</b>	<b>147</b>	<b>57</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(81)	(68)
Changes in restricted cash		5
Other investing activities		2
<b>Net cash flows used in investing activities</b>	<b>(81)</b>	<b>(61)</b>
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(30)	69
Dividends paid on common stock	(38)	(62)
<b>Net cash flows (used in) provided by financing activities</b>	<b>(68)</b>	<b>7</b>
<b>(Decrease) Increase in cash and cash equivalents</b>	<b>(2)</b>	<b>3</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>5</b>	<b>4</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 3</b>	<b>\$ 7</b>

See the Combined Notes to Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 3	\$ 5
Accounts receivable, net		
Customer	149	154
Other	40	96
Inventories, net		
Gas held in storage	4	8
Materials and supplies	34	32
Regulatory assets	67	72
Other	22	21
Total current assets	319	388
<b>Property, plant and equipment, net</b>	<b>3,132</b>	<b>3,070</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	295	299
Goodwill	8	8
Prepaid pension asset	197	202
Other	8	2
Total deferred debits and other assets	508	511
<b>Total assets</b>	<b>\$ 3,959</b>	<b>\$ 3,969</b>

See the Combined Notes to Financial Statements

**Table of Contents****DELMARVA POWER & LIGHT COMPANY****BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 75	\$ 105
Long-term debt due within one year	218	204
Accounts payable	100	109
Accrued expenses	44	31
Payables to affiliates	42	20
Customer deposits	35	31
Regulatory liabilities	57	49
Merger related obligation	76	
Other	9	15
<b>Total current liabilities</b>	<b>656</b>	<b>564</b>
<b>Long-term debt</b>		
	1,047	1,061
<b>Deferred credits and other liabilities</b>		
Regulatory liabilities	109	111
Deferred income taxes and unamortized investment tax credits	939	945
Non-pension postretirement benefit obligations	21	19
Other	60	32
<b>Total deferred credits and other liabilities</b>	<b>1,129</b>	<b>1,107</b>
<b>Total liabilities</b>	<b>2,832</b>	<b>2,732</b>
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	612	612
Retained earnings	515	625
<b>Total shareholder s equity</b>	<b>1,127</b>	<b>1,237</b>
<b>Total liabilities and shareholder s equity</b>	<b>\$ 3,959</b>	<b>\$ 3,969</b>

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

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
<b>Balance, December 31, 2015</b>	\$ 612	\$ 625	\$ 1,237
Net loss		(72)	(72)
Common stock dividends		(38)	(38)
<b>Balance, March 31, 2016</b>	\$ 612	\$ 515	\$ 1,127

See the Combined Notes to Financial Statements

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**ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2016	2015
<b>Operating revenues</b>		
Electric operating revenues	\$ 290	\$ 333
Operating revenues from affiliates	1	1
Total operating revenues	291	334
<b>Operating expenses</b>		
Purchased power	157	191
Purchased power from affiliates	1	
Operating and maintenance	211	68
Operating and maintenance from affiliates	1	1
Depreciation, amortization and accretion	40	43
Taxes other than income	2	2
Total operating expenses	412	305
<b>Operating (loss) income</b>	(121)	29
<b>Other income and (deductions)</b>		
Interest expense, net	(16)	(16)
Other, net	4	1
Total other income and (deductions)	(12)	(15)
<b>(Loss) Income before income taxes</b>	(133)	14
<b>Income taxes</b>	(33)	5
<b>Net (loss) income attributable to common shareholder</b>	\$ (100)	\$ 9
<b>Comprehensive (loss) income</b>	\$ (100)	\$ 9

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
<b>Cash flows from operating activities</b>		
Net (loss) income	\$ (100)	\$ 9
Adjustments to reconcile net (loss) income to net cash from operating activities:		
Depreciation, amortization and accretion	40	43
Deferred income taxes and amortization of investment tax credits	(33)	5
Other non-cash operating activities	132	8
Changes in assets and liabilities:		
Accounts receivable	5	(44)
Receivables from and payables to affiliates, net	20	2
Inventories	(2)	(1)
Accounts payable and accrued expenses	19	21
Income taxes	168	
Other assets and liabilities	(3)	20
Net cash flows provided by operating activities	246	63
<b>Cash flows from investing activities</b>		
Capital expenditures	(101)	(54)
Changes in restricted cash	1	
Other investing activities		1
Net cash flows used in investing activities	(100)	(53)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(5)	16
Retirement of long-term debt	(11)	(10)
Dividends paid on common stock	(11)	(12)
Net cash flows used in financing activities	(27)	(6)
<b>Increase in cash and cash equivalents</b>	<b>119</b>	<b>4</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>3</b>	<b>2</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 122</b>	<b>\$ 6</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 122	\$ 3
Restricted cash and cash equivalents	11	12
Accounts receivable, net		
Customer	146	156
Other	74	242
Inventories, net	24	23
Regulatory assets	95	98
Other	13	12
<b>Total current assets</b>	<b>485</b>	<b>546</b>
<b>Property, plant and equipment, net</b>	<b>2,384</b>	<b>2,322</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	419	414
Long-term note receivable	4	4
Prepaid pension asset	79	82
Other	22	19
<b>Total deferred debits and other assets</b>	<b>524</b>	<b>519</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 3,393</b>	<b>\$ 3,387</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2016 (Unaudited)	December 31, 2015
<b>LIABILITIES AND SHAREHOLDER S EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$	\$ 5
Long-term debt due within one year	47	48
Accounts payable	101	96
Accrued expenses	77	70
Payables to affiliates	36	16
Customer deposits	35	30
Regulatory liabilities	22	18
Merger related obligation	110	
Other	16	14
Total current liabilities	444	297
<b>Long-term debt</b>		
	1,144	1,153
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	854	885
Non-pension postretirement benefit obligations	35	33
Regulatory liabilities	5	7
Other	22	12
Total deferred credits and other liabilities	916	937
Total liabilities <sup>(a)</sup>	2,504	2,387
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	773	773
Retained earnings	116	227
Total shareholder s equity	889	1,000
<b>Total liabilities and shareholder s equity</b>	<b>\$ 3,393</b>	<b>\$ 3,387</b>

(a) ACE s consolidated total assets include \$29 million and \$30 million at March 31, 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 \$161 million and \$172 million at March 31, 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.

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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
<b>Balance, December 31, 2015</b>	\$ 773	\$ 227	\$ 1,000
Net loss		(100)	(100)
Common stock dividends		(11)	(11)
<b>Balance, March 31, 2016</b>	\$ 773	\$ 116	\$ 889

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****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**

<b>Registrant</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>6</b>	<b>7</b>	<b>8</b>	<b>9</b>	<b>10</b>	<b>11</b>	<b>12</b>	<b>13</b>	<b>14</b>	<b>15</b>	<b>16</b>	<b>17</b>	<b>18</b>	<b>19</b>	<b>20</b>	
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, and engages in natural gas and oil exploration and production activities (Upstream). Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

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

*PECO:* Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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

*DPL:* Purchase and regulated retail sale of electricity and the provision of electric distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.

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

**Basis of Presentation (All Registrants)**

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 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 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 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.



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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

***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 by 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 now 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 is an increase of \$1 million and \$5 million for the three months ended March 31, 2016 and March 31, 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 three months ended March 31, 2016 is less than \$1 million for each of PHI Successor, PHI Predecessor and DPL, and \$1 million for each of Pepco and ACE. The reclassification in the Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2015 is less than \$1 million for PHI, Pepco, DPL and ACE, respectively. 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 March 31, 2016 and 2015 and for the three months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants' respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 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. These notes should be read in conjunction with the Combined Notes to Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2015 Form 10-K Reports.

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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****2. New Accounting Pronouncements (All Registrants)**

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

***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. In August 2015, the FASB issued an amendment to provide a one year deferral of the effective date to annual reporting periods beginning on or after December 15, 2017, as well as an 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 final amendments to clarify the implementation guidance for principal versus agent considerations, identifying performance obligations and the accounting for licenses of intellectual property. In May 2016, the FASB issued a final amendment regarding narrow scope improvements and practical expedients. The Registrants are currently assessing the impact of these updates.

***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.

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**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. Based on the analysis completed, additional entities were considered VIEs. See Note 3 Variable Interest Entities for the disclosure impacts.

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

***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

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

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 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 redesignation 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 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.

***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

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

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.

***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 March 31, 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 March 31, 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 a total of \$250 million of equity incrementally from inception through December 2016 in proportion to their ownership interests, which equates to approximately \$172 million for the tax equity investor and \$78 million for Generation (see Note 18 – Commitments and Contingencies for more details). The investment in the distributed energy company was

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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,

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 March 31, 2016 and December 31, 2015, ComEd, PECO, Pepco and DPL do not have any material consolidated VIEs.

As of March 31, 2016 and December 31, 2015, Exelon, Generation, BGE, PHI and ACE provided the following support to their respective consolidated VIEs:

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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,

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 March 31, 2016, the remaining obligation is \$304 million, including accrued interest, which reflects the principal payment made in January 2015,

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 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 March 31, 2016, the remaining obligation is immaterial,

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 \$7 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 \$14 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 months ended March 31, 2016 and 2015, BGE remitted \$20 million and \$21 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

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

Bond Charge from ACE customers pursuant to bondable stranded costs rate orders issued by the NJBPU in an amount sufficient to fund the principal and interest payments on transition bonds and related taxes, expenses and fees. During the three months ended March 31, 2016 and 2015, ACE transferred \$14 million and \$13 million to ATF, respectively.

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

the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;

Exelon, Generation, 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 March 31, 2016 and December 31, 2015 are as follows:

	March 31, 2016					December 31, 2015				
	Exelon <sup>(a)(b)</sup>	Generation	BGE	Successor		Exelon <sup>(a)</sup>	Generation	BGE	Predecessor	
				PHI <sup>(b)</sup>	ACE				PHI	ACE
Current assets	\$ 928	\$ 860	\$ 44	\$ 22	\$ 11	\$ 909	\$ 881	\$ 23	\$ 12	\$ 12
Noncurrent assets	8,047	7,996	3	46	18	8,009	8,004	3	18	18
<b>Total assets</b>	<b>\$ 8,975</b>	<b>\$ 8,856</b>	<b>\$ 47</b>	<b>\$ 68</b>	<b>\$ 29</b>	<b>\$ 8,918</b>	<b>\$ 8,885</b>	<b>\$ 26</b>	<b>\$ 30</b>	<b>\$ 30</b>
Current liabilities	\$ 544	\$ 400	\$ 83	58	\$ 47	\$ 473	\$ 387	\$ 81	\$ 48	\$ 48
Noncurrent liabilities	3,050	2,865	41	142	114	2,927	2,884	41	124	124
<b>Total liabilities</b>	<b>\$ 3,594</b>	<b>\$ 3,265</b>	<b>\$ 124</b>	<b>\$ 200</b>	<b>\$ 161</b>	<b>\$ 3,400</b>	<b>\$ 3,271</b>	<b>\$ 122</b>	<b>\$ 172</b>	<b>\$ 172</b>

(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.

**Table of Contents****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 March 31, 2016 and December 31, 2015, these assets and liabilities primarily consisted of the following:

	March 31, 2016					December 31, 2015				
	Exelon <sup>(a)(b)</sup>	Generation	Successor			Exelon <sup>(a)</sup>	Generation	Predecessor		
			BGE	PHI <sup>(b)</sup>	ACE			BGE	PHI	ACE
Cash and cash equivalents	\$ 145	\$ 145	\$	\$	\$	\$ 164	\$ 164	\$	\$	\$
Restricted cash	117	62	44	11	11	100	77	23	12	12
Accounts receivable, net										
Customer	231	231				219	219			
Other	28	28				43	43			
Mark-to-market derivatives assets	120	120				140	140			
Inventory										
Materials and supplies	186	186				181	181			
Other current assets	50	36		11		35	30			
Total current assets	877	808	44	22	11	882	854	23	12	12
Property, plant and equipment, net	5,141	5,141				5,160	5,160			
Nuclear decommissioning trust funds	2,069	2,069				2,036	2,036			
Goodwill	47	47				47	47			
Mark-to-market derivatives assets	41	41				53	53			
Other noncurrent assets	135	84	3	46	18	90	85	3	18	18
Total noncurrent assets	7,433	7,382	3	46	18	7,386	7,381	3	18	18
Total assets	\$ 8,310	\$ 8,190	\$ 47	\$ 68	\$ 29	\$ 8,268	\$ 8,235	\$ 26	\$ 30	\$ 30
Long-term debt due within one year	\$ 265	\$ 128	\$ 79	\$ 56	\$ 45	\$ 111	\$ 27	\$ 79	\$ 46	\$ 46
Accounts payable	164	164				216	216			
Accrued expenses	81	75	4	2	2	115	113	2	2	2
Mark-to-market derivative liabilities	7	7				5	5			
Unamortized energy contract liabilities	12	12				12	12			
Other current liabilities	13	13				13	13			
Total current liabilities	542	399	83	58	47	472	386	81	48	48
Long-term debt	743	559	41	142	114	666	623	41	124	124
Asset retirement obligations	2,016	2,016				1,999	1,999			
Pension obligation <sup>(c)</sup>	9	9				9	9			

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Unamortized energy contract liabilities	35	35				39	39			
Other noncurrent liabilities	76	76				79	79			
Total noncurrent liabilities	2,879	2,695	41	142	114	2,792	2,749	41	124	124
Total liabilities	\$ 3,421	\$ 3,094	\$ 124	\$ 200	\$ 161	\$ 3,264	\$ 3,135	\$ 122	\$ 172	\$ 172

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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

- (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 March 31, 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 \$18 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 \$18 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, 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.



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

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 a total of \$250 million of equity incrementally from inception through December 2016 in proportion of their ownership interests, which equates to approximately \$172 million for the tax equity investor and \$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:

	<b>Commercial Agreement VIEs</b>	<b>Equity Investment VIEs</b>	<b>Total</b>
<b>March 31, 2016</b>			
Total assets <sup>(a)</sup>	\$ 264	\$ 357	\$ 621
Total liabilities <sup>(a)</sup>	15	247	262
Exelon’s ownership interest in VIE <sup>(b)</sup>		75	75
Other ownership interests in VIE <sup>(a)</sup>	249	35	284
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments		94	94
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning <sup>(b)</sup>	17		17

	<b>Commercial Agreement VIEs</b>	<b>Equity Investment VIEs</b>	<b>Total</b>
<b>December 31, 2015</b>			
Total assets <sup>(a)</sup>	\$ 263	\$ 164	\$ 427
Total liabilities <sup>(a)</sup>	22	125	147
Exelon’s ownership interest in VIE <sup>(b)</sup>		11	11
Other ownership interests in VIE <sup>(a)</sup>	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 <sup>(b)</sup>	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 \$183 million and \$206 million as of March 31, 2016 and December 31, 2015, respectively; offset by payables to ZionSolutions LLC of \$166 million and \$189 million as of March 31, 2016 and December 31, 2015, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

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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.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****4. Mergers, Acquisitions and Dispositions****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***

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, concluding that the merger as presented was not in the public interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, various parties, including Exelon and PHI, entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief.

On October 28, 2015, the DCPSC agreed to reopen the approval application to allow for consideration of the Settlement Agreement. On February 26, 2016, the DCPSC rejected the Settlement Agreement and also voted that the merger would be deemed approved without further DCPSC action if the Settlement Agreement was modified in specific ways (Revised Settlement Agreement), and if such modifications were acceptable to Exelon, PHI, the District of Columbia Government, the Office of People's Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust-Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties). On March 7, 2016, Exelon and PHI made a filing with the DCPSC requesting approval of the merger through either (1) the adoption of the Settlement Agreement as originally executed by the Settling Parties, (2) the adoption of the Revised Settlement Agreement as a resolution on the merits, or (3) the adoption of a compromise position with modifications to the Revised Settlement Agreement. On March 23, 2016, the DCPSC approved the merger through the adoption of the Revised Settlement Agreement with a minor modification.

Approval of the merger across all jurisdictions 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. Exelon estimates total commitments of approximately \$444 million on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided. The actual cost of commitments may differ by a material amount depending on the result of final negotiations and application of the most favored nation provision. The following pre-tax costs were recognized, including the estimated impacts of applying the most favored nation

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

provision, after the closing of the merger and are included in Operating and maintenance expense in Exelon's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2016 and PHI's successor Consolidated Statement of Operations and Comprehensive Income:

Description	Expected		Successor				
	Payment Period		Pepco	DPL	ACE	PHI	Exelon
Customer bill credit	2016	2017	\$ 65	\$ 58	\$ 62	\$ 185	\$ 185
Energy efficiency	2016	2021					64
Charitable contributions	2016	2026	28	12	10	50	50
Customer base rate credit	2016	2019	26			26	26
Delivery system modernization	Q2 2016						22
Green sustainability fund	Q2 2016						14
Workforce development	2016	2020					11
Most favored nation			19	32	48	99	129
Other			1	2		3	7
Total			\$ 139	\$ 104	\$ 120	\$ 363	\$ 508

Pursuant to the orders approving the merger, Exelon expects to make \$73 million, \$46 million and \$49 million 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 32 MWs of new generation in Maryland and the District of Columbia, 27MWs of which are expected to be completed by 2018. These investments are expected to total approximately \$130 million. These investments are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. Investment costs will be recognized as incurred and recorded on Exelon's and Generation's financial statements. Exelon has also committed to purchase 100MW of wind energy to procure, under certain circumstances, 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 has been 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 Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval, with a decision not anticipated until the second or third quarter of 2016. Exelon does not believe resolution of these suits will have a material impact on Exelon's results of operations or cash flows.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC's motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George's

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

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 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.

On March 25, 2016, Grid 2.0 filed an application for reconsideration of the DCPSC's March 23, 2016 order approving the merger. On March 30, 2016, Exelon filed a reply to that application. The DCPSC has tolled the date to act upon the application until May 25, 2016 and, therefore, the DCPSC is expected to issue an order ruling on these motions by that date. On April 20, 2016, DC Public Power filed a motion to reconsider the DCPSC's March 23, 2016 order, motion to intervene and motion to consider alternative settlement provisions (namely, that the DCPSC consider requiring the post-merger divestiture of Pepco's DC-based assets to a not-for-profit independent grid operator). On April 27, 2016, Exelon filed a reply to these motions. The DCPSC is expected to issue an order ruling on these motions by May 20, 2016. On April 22, 2016, (1) the District of Columbia Office of People's Counsel, (2) the District of Columbia Government, and (3) DC Sun and Public Citizen each filed separate applications for reconsideration of the DCPSC's March 23, 2016 order. On April 29, 2016, Exelon filed a reply to these applications. The DCPSC is expected to issue an order ruling on these applications by May 23, 2016. These applications for reconsideration generally argue that the DCPSC violated its regulations, utilized improper processes, abused its discretion, acted arbitrarily and capriciously, committed legal error and denied due process in approving the merger under terms that revised the Settlement Agreement offered by the companies and various parties. 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:

<b>(In millions of dollars, except per share data)</b>	<b>Total Consideration</b>
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 <sup>(a)</sup>	180
Cash paid for PHI stock-based compensation equity awards <sup>(b)</sup>	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 Sheet.

(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.

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

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

**Preliminary Purchase Price Allocation**

Current assets	\$ 2,107
Property, plant and equipment	11,071
Regulatory assets	5,118
Other assets	656
Goodwill	4,016
 Total assets	 22,968
Current liabilities	3,425
Unamortized energy contracts	1,550
Regulatory liabilities	297
Long-term debt, including current maturities	6,076
Deferred income taxes	3,441
Pension and OPEB liability	846
Other liabilities	191
 Total liabilities	 15,826
 Total purchase price	 \$ 7,142

On its successor financial statements, PHI has recorded beginning March 24, 2016, Membership interest equity of \$7.2 billion, greater than the total \$7.1 billion purchase price, reflecting the impacts 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, \$1.2 billion and \$1.1 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. Of this amount, 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 and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

**Table of Contents****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 three months ended March 31, 2016 was as follows:

	<b>PHI</b>	<b>Exelon<sup>(a)</sup></b>
Beginning balance	\$	\$ 2,672
Goodwill from business combination	4,016	4,016
Ending balance	\$ 4,016	\$ 6,688

(a) As of March 31, 2016, there were no changes to the carrying amount of goodwill for ComEd and Generation, 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 plant, property 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 March 31, 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. Amortizations were not significant for the period March 24, 2016 to March 31, 2016 at Exelon or PHI.

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

The valuations performed in the first quarter of 2016 to assess the fair value of certain assets acquired and liabilities assumed are 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, if not sooner. The significant assets and liabilities for which preliminary valuation amounts are recognized at March 31, 2016 include the fair value of intangible assets and liabilities, uncertain tax positions, deferred income tax assets and liabilities, pension and OPEB plans, long-term debt, and unregulated property, plant and equipment. The preliminary amounts recognized are subject to revision until the valuations are completed and 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.

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 quarter impact of PHI, including its unregulated businesses, on Exelon's Consolidated Statement of Operations and Comprehensive Income includes Operating revenues of \$107 million and Net loss of \$(315) million during the three months ended March 31, 2016.

For the periods ended March 31, 2016 and 2015, Exelon and PHI have recognized expense to achieve the PHI acquisition as follows:

Acquisition, Integration and Financing Costs <sup>(a)</sup>	Three Months Ended March 31,	
	2016	2015
Exelon	\$ 102	\$ 108
Generation	16	7
ComEd <sup>(b)</sup>	(8)	3
PECO	2	1
BGE	2	1
Pepco	27	1
DPL	16	1
ACE	13	1

  

Acquisition, Integration and Financing Costs <sup>(a)</sup>	Successor March 24, 2016 to March 31, 2016		Predecessor January 1, 2016 to March 31, 2015	
	2016	2016	2015	2015
PHI	\$ 56	\$ 29	\$ 29	\$ 8

(a) The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statement 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) Excludes acquisition, integration and financing costs of \$9 million incurred at ComEd that have been recorded as a regulatory asset.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****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.

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 March 31, 2016 <sup>(a)</sup>	Three Months Ended March 31, 2015 <sup>(b)</sup>	Year Ended December 31, 2015 <sup>(c)</sup>
Total operating revenues	\$ 8,556	\$ 10,062	\$ 33,823
Net income attributable to common shareholders	577	800	2,618
Basic earnings per share	\$ 0.63	\$ 0.87	\$ 2.85
Diluted earnings per share	0.62	0.87	2.84

- (a) The amounts above exclude non-recurring costs directly related to the merger of \$639 million and intercompany revenue of \$170 million for the three months ended March 31, 2016.
- (b) The amounts above exclude non-recurring costs directly related to the merger of \$116 million and intercompany revenue of \$122 million for the three months ended March 31, 2015.
- (c) The amounts above exclude non-recurring costs directly related to the merger of \$92 million and intercompany revenue of \$559 million for the year ended December 31, 2015.

**Asset Divestitures (Exelon, Generation, PHI, Pepco and ACE)**

At March 31, 2016, Generation had net liabilities held for sale of \$5 million which were reflected within Other current assets and Other current liabilities in the Consolidated Balance Sheet. The assets held for sale at December 31, 2015 were not material. On April 21, 2016, Generation completed the sale of the retired New Boston generating site, located in the Boston, Massachusetts, resulting in a pre-tax gain of approximately \$32 million to be recorded in the second quarter. In addition, Pepco and ACE had net assets held for sale of \$4 million and \$1 million, respectively, which were reflected within Other current assets and Other current liabilities in their Consolidated Balance Sheets. The assets held for sale at December 31, 2015 were not material. 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 to be recorded in the second quarter. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain will be 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

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

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.

**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. 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 numerous easements across the project route through voluntary transactions. ComEd is seeking to acquire the remaining rights either through settlement or condemnation proceedings that are currently pending in the relevant circuit courts. ComEd began construction of the line during the second quarter of 2015 with an expected in-service date of the second quarter of 2017.

**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 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, 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 appealed the Court's decision. On April 5, 2016, the PAPUC's request for appeal was denied. PECO does not have information at this time as to what action it may be required to take following remand to the PAPUC.

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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 is procuring 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) will move to spot market pricing. As of March 31, 2016, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the first three 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. The program has a 24-month term from June 1, 2017 through May 31, 2019, and complies with electric generation procurement guidelines set forth in Act 129. A PAPUC ruling is expected in late 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. The order tentatively established PECO's five-year cumulative consumption reduction target at 2,080,553 MWh.

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 on March 17, 2016, subject to clarification of a few minor issues. PECO refiled its Phase III Plan, with all requested clarifications, on March 31, 2016.

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 annual service revenues for electric delivery, based on a requested ROE of 10.6%. Any adjustments to rates approved by the MDPSC are expected to take effect in November 2016. In addition to the proposed \$127 million rate increase, Pepco is proposing to continue its Grid Resiliency Charge initially approved in July 2013 in connection with Pepco's electric distribution rate case filed in November 2012. In connection with the Grid Resiliency Charge, 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 increase the MDPSC will approve or if it will approve Pepco's Grid Resiliency Charge proposal.

**2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE).** On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and 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.

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

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 March 31, 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 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.

**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 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 March 31, 2016 and December 31, 2015, BGE recorded a regulatory asset of \$212 million and \$196 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE's 2014 electric and gas distribution rate case, the cost of the retired non-AMI meters will be amortized over 10 years.

As part of the 2015 electric and gas distribution rate case filed on November 6, 2015, BGE is seeking recovery of its smart grid initiative costs. Of BGE's requested \$197 million, \$141 million relates to the smart grid initiative. In support of its recovery of smart grid initiative costs, BGE provided evidence demonstrating that the benefits exceed the costs on a present value basis by a ratio of 2.3 to 1.0, on a nominal basis. For further information, see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

**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 MW beginning in 2015, in amounts proportional to their relative SOS loads. Under the terms of the order, the winning bidder will 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 will 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

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

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.

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. The U.S. Supreme Court decision will likely moot the state court action pending in the Court of Special Appeals of Maryland.

**Delaware Regulatory Matters**

**Gas Cost Rates. (Exelon, PHI and DPL)** DPL makes an annual GCR filing with the DPSC for the purpose of allowing DPL to recover natural gas procurement costs through customer rates. In August 2015, DPL made its 2015 GCR filing. The rates proposed in the 2015 GCR filing would result in a GCR decrease of approximately 26%, primarily reflecting lower natural gas prices. On September 22, 2015, the DPSC issued an order allowing DPL to place the new rates into effect on November 1, 2015, subject to refund and pending final DPSC approval. On March 22, 2016, the DPSC approved the Gas Cost Rate as filed.

**2013 Electric Distribution Base Rates (Exelon, PHI and DPL).** In March 2013, and as amended on September 20, 2013, DPL filed for an electric distribution base rate increase with the DPSC, ultimately requesting an annual increase of \$42 million.

In August 2014, the DPSC issued a final order in DPL's 2013 electric distribution rate case for an annual increase of \$15 million and an ROE of 9.70%. Rates became effective on May 1, 2014.

In September 2014, DPL filed an appeal with the Delaware Superior Court of the DPSC's August 2014 order in this proceeding, seeking the court's review of the DPSC's decision relating to the recovery of costs associated with one component of employee compensation, certain retirement benefits and credit facility expenses. The Division of the Public Advocate filed a cross-appeal in September 2014, pertaining to the treatment of a prepaid pension expense and other postretirement benefit obligations in base rates. Under the Settlement Agreement related to the Merger, the parties agreed to suspend the appeal and, upon consummation of the Merger, to the withdrawal of the appeal and the cross-appeal with prejudice. In accordance with the settlement, on April 13, 2016, the parties filed a Stipulation of Dismissal with the court to dismiss the appeal and the cross-appeal. The court has not yet acted on this filing.

**District of Columbia Regulatory Matters**

**District of Columbia Power Line Undergrounding Initiative (Exelon, PHI and Pepco).** On May 3, 2014, the Council of the District of Columbia enacted the Electric Company Infrastructure Improvement Financing Act of 2014 (the Improvement Financing Act), which provides enabling legislation for the DC PLUG initiative. This \$1 billion initiative seeks to selectively place underground some of the District of Columbia's most outage-prone power lines, which lines and surrounding conduit would be owned and maintained by Pepco.

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 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 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 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

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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.

On June 17, 2014, Pepco and DDOT filed a Triennial Plan related to the construction of selected underground feeders in the District of Columbia and recovery of Pepco's investment through a volumetric surcharge (the Triennial Plan), all in accordance with the Improvement Financing Act. On August 1, 2014, Pepco filed an application for the issuance of a financing order to provide for the issuance of the District's bonds and a volumetric surcharge for the District to recover the costs associated with the bond issuance (the DDOT surcharge).

On November 12, 2014, the DCPSC issued an order approving the Triennial Plan and Pepco's volumetric surcharge, and issued the financing order, including approval of the DDOT surcharge. Together these orders permit (i) Pepco and DDOT to commence proposed construction under the Triennial Plan; (ii) the District of Columbia to issue the necessary bonds to fund the District of Columbia's portion of the DC PLUG initiative; and (iii) the establishment of the customer surcharges contemplated by the Improvement Financing Act.

In March 2015, a party to the DCPSC proceedings filed with the District of Columbia Court of Appeals a petition for review of the order approving the Triennial Plan and the issuance of the financing order. On January 14, 2016, the District of Columbia Court of Appeals affirmed the orders of the DCPSC. On January 27, 2016, the original petitioning party sought rehearing of the District of Columbia Court of Appeals decision. On March 17, 2016, the District of Columbia Court of Appeals denied the original petitioning party's motion for rehearing.

Separately, 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 delay implementation of the DC PLUG initiative.

**New Jersey Regulatory Matters**

**2016 Electric Distribution Base Rates (Exelon, PHI and ACE).** On March 22, 2016, ACE filed an application with the NJBPU requesting an increase of \$84 million to its annual service revenues for electric delivery, based on a requested ROE of 10.6%. In addition to the request for base rate relief, ACE has also included a request that the NJBPU approve ACE's five-year grid resiliency initiative known as PowerAhead. As proposed, PowerAhead includes \$176 million of 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. A decision is expected in the first half of 2017. ACE cannot predict how much of the requested increase the NJBPU will approve or if it will approve ACE's PowerAhead initiative.

**Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE).** On 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 uncollected 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. ACE has requested that the NJBPU place the new rates into effect by June 1, 2016.

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

**Standard Offer Capacity Agreements (Exelon, PHI and ACE).** On April 28, 2011, ACE entered into three SOCAs by order of the NJBPU, each with a different generation company. ACE and the other New Jersey EDCs entered into the SOCAs under protest, arguing that the EDCs were denied due process and that the SOCAs violated certain of the requirements of the New Jersey law under which the SOCAs were established (the NJ SOCA Law). On October 22, 2013, in light of the decision of the U.S. District Court for the District of New Jersey described below, the state appeals of the NJBPU implementation orders filed by the EDCs and generators were dismissed without prejudice, subject to the parties exercising their appellate rights in the Federal courts.

In February 2011, ACE joined other plaintiffs in an action filed in the U.S. District Court for the District of New Jersey challenging the NJ SOCA Law on the grounds that it violates the Commerce Clause and the Supremacy Clause of the U.S. Constitution. In October 2013, the Federal district court issued a ruling that the NJ SOCA Law is preempted by the Federal Power Act (FPA) and violates the Supremacy Clause, and is therefore null and void. On October 11, 2013, the Federal district court issued an order ruling that the SOCAs are void, invalid and unenforceable, which order was affirmed by the U.S. Court of Appeals for the Third Circuit on September 11, 2014.

On November 26, 2014 and December 10, 2014, respectively, one of the generation companies and the NJBPU petitioned the U.S. Supreme Court to consider hearing an appeal of the Third Circuit decision. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit decision, discussed above under MDPSC New Generation Contract Requirement, holding that the MDPSC's required contracts are illegal and unenforceable. On April 25, 2016, the U.S. Supreme Court ruled not to review the Third Circuit decision. This denial leaves the Third Circuit decision in place, with the same outcome as the Fourth Circuit decision.

ACE terminated one of the three SOCAs effective July 1, 2013 due to the occurrence of an event of default on the part of the generation company counterparty. ACE terminated the remaining two SOCAs effective November 19, 2013, in response to the October 2013 Federal district court decision.

**New York Regulatory Matters**

**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 New York Public Service Commission (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 will begin recognizing revenue based on the final approved pricing contained in the RSSA. Generation will also recognize 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 non-controlling interest in CENG.

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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.

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 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.

The approved RSSA requires Ginna to continue operating through the RSSA term. There remains an increased risk that, for economic reasons, Ginna could be retired before the end of its operating license period in 2029 if an adequate regulatory or legislative solution is not adopted in New York. 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-Implications of Potential Early 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).** The following tables provide information about the net regulatory asset or liabilities associated with the transmission formula rate of the indicated registrants as of March 31, 2016 and December 31, 2015. The regulatory asset associated with the transmission true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

As of March 31, 2016	Exelon	ComEd	BGE	Successor			
				PHI	Pepco	DPL	ACE
Regulatory Assets <sup>(a)</sup>	\$ 60	\$ 31	\$ 17	\$ 12	\$ 4	\$ 7	\$ 1

As of December 31, 2015	Exelon	ComEd	BGE	Predecessor			
				PHI	Pepco	DPL	ACE
Regulatory Assets <sup>(a)(b)</sup>	\$ 43	\$ 31	\$ 12	\$ 14	\$ 5	\$ 7	\$ 2

(a) The regulatory assets represent a component of the costs included within the energy and transmission regulatory programs. Refer to Regulatory Assets and Liabilities table for additional information.

(b) The Exelon consolidated amounts do not include the regulatory assets of PHI, Pepco, DPL, and ACE at December 31, 2015.

On April 13, 2016, ComEd filed its annual transmission formula rate update based upon the FERC approved formula with the FERC. The filing establishes the revenue requirement used to set rates that will take effect in June 2016, subject to review by the FERC and other parties, which is due by fourth quarter 2016. ComEd's 2016 annual update includes a total increase to the revenue requirement of \$94 million, reflecting an increase of \$90 million for the initial revenue requirement and an increase of \$4 million related to the annual reconciliation. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.47%, inclusive of an allowed ROE of 11.50%, a decrease from the 8.61% average debt and equity return previously authorized.

On April 27, 2016, BGE filed its annual transmission formula rate update based upon the FERC approved formula with the FERC. The filing establishes the revenue requirement used to set rates that will take effect in June 2016, subject to review by the FERC and other parties, which is due by third quarter 2016. BGE's 2016





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annual update includes a total increase to the revenue requirement of \$15 million, reflecting an increase of \$12 million for the initial revenue requirement and a decrease of \$3 million related to the annual reconciliation. This increase excludes the \$13 million increase in revenue requirement associated with dedicated facilities charges. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.09%, inclusive of an allowed ROE of 10.50% a decrease from the 8.46% average debt and equity return previously authorized.

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.

**FERC Transmission Complaint (Exelon, BGE, PHI, Pepco, DPL and ACE).** In February 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE, Pepco, DPL and ACE relating to their respective transmission formula rates. BGE's formula rate included a 10.8% base ROE and a 50 basis point incentive for participating in PJM (and certain additional incentive base points on certain projects). Pepco's, DPL's and ACE's formula rates included, for facilities placed into service after January 1, 2006, a base ROE of 11.3%, and for facilities placed into service prior to January 1, 2006, a base ROE of 10.8% and a 50 basis point incentive for participating in PJM. The parties sought a reduction in the base return on equity to 8.7% and changes to the formula rate process. Under FERC rules, any revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint.

On August 21, 2014, FERC issued an order in the proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013.

On February 23, 2016, FERC approved the settlement filed by the parties on November 6, 2015, covering the ROE issues raised in the complaints. The settlement provides for a 10% base ROE, effective March 8, 2016, which will be augmented by the PJM incentive adder of 50 basis points, and refunds to customers of BGE, Pepco, DPL and ACE of \$13.7 million, \$14.2 million, \$11.9 million and \$9.5 million, respectively. The settlement also prohibits any settling party from filing to change the base ROE or any incentives prior to June 1, 2018. The date for filing a request for rehearing has expired without any such requests having been filed. Accordingly, the order is not eligible for appeal and the matter is considered closed.

**Operating License Renewals (Exelon and Generation).** On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year license for the Conowingo Hydroelectric Project (Conowingo). Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish habitat, and (3) sediment. On January 30, 2014, Generation filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues. MDE indicated that it believed it did not have sufficient information to process Generation's application. As a result, Generation entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Generation has agreed to contribute up to \$3.5 million to fund the additional study. In addition, because of the ongoing sediment and nutrient monitoring study, and because states must act upon water quality certification applications within a year of submission, Exelon agreed with Maryland to coordinate the withdrawal and refiling of the application in accordance with FERC policy that requires an applicant to resubmit its request for a water quality certification within 90 days of the date of withdrawal.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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 DOI's preliminary prescription. On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all issues between Exelon and Interior relating to fish passage at Conowingo. 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 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 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.

The FERC license for Conowingo expired on September 1, 2014. Under the Federal Power Act, FERC is required to issue an annual license for a facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of an annual license, the annual license will renew automatically. On March 11, 2015, FERC issued the final Environmental Impact Statement for Conowingo. The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of March 31, 2016, \$25 million of direct costs associated with the Conowingo licensing effort have been capitalized.

**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 \$2.5 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting.

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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 March 31, 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.

March 31, 2016	Exelon	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
<b>Regulatory assets</b>								
Pension and other postretirement benefits <sup>(a)</sup>	\$ 4,261	\$	\$	\$	\$	\$	\$	\$
Deferred income taxes	1,861	65	1,499	80	217	139	35	43
AMI programs <sup>(r)</sup>	687	149	60	212	266	181	85	
Under-recovered distribution service costs <sup>(b)</sup>	198	198						
Debt costs <sup>(c)</sup>	132	45	1	8	86	19	9	7
Fair value of long-term debt <sup>(d)</sup>	896				741			
Fair value of PHI's unamortized energy contracts <sup>(s)</sup>	1,535				1,535			
Severance	8			8				
Asset retirement obligations	113	71	22	19	1	1		
MGP remediation costs	276	246	29	1				
Under-recovered uncollectible accounts	60	60						
Renewable energy	265	265						
Energy and transmission programs <sup>(f)(g)(m)(n)(o)</sup>	118	56		38	24	5	6	13
Deferred storm costs	47			2	45	19	6	20
Electric generation-related regulatory asset	18			18				
Rate stabilization deferral	77			67	10	9	1	
Energy efficiency and demand response programs	651		1	264	386	277	108	1
Merger integration costs	5			5				
Conservation voltage reduction	3			3				
Under-recovered revenue decoupling <sup>(h)</sup>	36			36				
COPCO acquisition adjustment	12				12		12	
Recoverable workers compensation and long-term disability	31				31	31		
Vacation accrual	43		17		26		15	11
Securitized stranded costs	185				185			185
CAP arrearage	8		8					
Removal costs	397				397	103	73	222
AEC <sup>(i)</sup>	7				7			
Other	61	9	10	4	34	12	12	12
<b>Total regulatory assets</b>	<b>11,991</b>	<b>1,164</b>	<b>1,647</b>	<b>765</b>	<b>4,003</b>	<b>796</b>	<b>362</b>	<b>514</b>
<b>Less: current portion</b>	<b>1,584</b>	<b>239</b>	<b>42</b>	<b>266</b>	<b>801</b>	<b>133</b>	<b>67</b>	<b>95</b>
<b>Total non-current regulatory assets</b>	<b>\$ 10,407</b>	<b>\$ 925</b>	<b>\$ 1,605</b>	<b>\$ 499</b>	<b>\$ 3,202</b>	<b>\$ 663</b>	<b>\$ 295</b>	<b>\$ 419</b>

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

<b>March 31, 2016</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<i>Successor</i> <b>PHI</b>	<b>Pepco</b>	<b>DPL</b>	<b>ACE</b>
<b>Regulatory liabilities</b>								
Other postretirement benefits	\$ 93	\$	\$	\$	\$	\$	\$	\$
Nuclear decommissioning	2,599	2,182	417					
Removal costs	1,669	1,334		187	148	21	127	
Deferred rent <sup>(i)</sup>	42				42			
Energy efficiency and demand response programs	122	78	43		1			1
DLC program costs	9		9					
Electric distribution tax repairs	89		89					
Gas distribution tax repairs	25		25					
Energy and transmission programs <sup>(f)(g)(k)(l)(p)(q)</sup>	187	43	69	15	60	25	25	10
Other	55	2	3	10	41	9	14	16
<b>Total regulatory liabilities</b>	<b>4,890</b>	<b>3,639</b>	<b>655</b>	<b>212</b>	<b>292</b>	<b>55</b>	<b>166</b>	<b>27</b>
Less: current portion	512	150	134	61	106	26	57	22
<b>Total non-current regulatory liabilities</b>	<b>\$ 4,378</b>	<b>\$ 3,489</b>	<b>\$ 521</b>	<b>\$ 151</b>	<b>\$ 186</b>	<b>\$ 29</b>	<b>\$ 109</b>	<b>\$ 5</b>

<b>December 31, 2015</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<i>Predecessor</i> <b>PHI</b>	<b>Pepco</b>	<b>DPL</b>	<b>ACE</b>
<b>Regulatory assets</b>								
Pension and other postretirement benefits	\$ 3,156	\$	\$	\$	\$ 910	\$	\$	\$
Deferred income taxes	1,616	64	1,473	79	214	137	36	41
AMI programs <sup>(r)</sup>	399	140	63	196	267	180	87	
Under-recovered distribution service costs <sup>(b)</sup>	189	189						
Debt costs	47	46	1	8	36	19	10	7
Fair value of long-term debt <sup>(d)</sup>	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						
Energy and transmission programs <sup>(f)(g)(k)(m)(n)(o)</sup>	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	14	10	4	
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 <sup>(h)</sup>	30			30				
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

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Other	29	10	13	3	38	14	10	13
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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

December 31, 2015	Exelon	ComEd	PECO	BGE	<i>Predecessor</i> PHI	Pepco	DPL	ACE
<b>Regulatory liabilities</b>								
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 <sup>(f)(g)(k)(l)(p)(q)</sup>	131	53	60	18	27	16	19	8
Over-recovered revenue decoupling <sup>(h)</sup>	1			1				
Other	16	5	2	8	35	7	12	16
<b>Total regulatory liabilities</b>	<b>4,570</b>	<b>3,614</b>	<b>639</b>	<b>222</b>	<b>213</b>	<b>44</b>	<b>160</b>	<b>25</b>
<b>Less: current portion</b>	<b>369</b>	<b>155</b>	<b>112</b>	<b>38</b>	<b>66</b>	<b>15</b>	<b>49</b>	<b>18</b>
<b>Total non-current regulatory liabilities</b>	<b>\$ 4,201</b>	<b>\$ 3,459</b>	<b>\$ 527</b>	<b>\$ 184</b>	<b>\$ 147</b>	<b>\$ 29</b>	<b>\$ 111</b>	<b>\$ 7</b>

- (a) As of March 31, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of \$1,125 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 March 31, 2016, ComEd's regulatory asset of \$198 million was comprised of \$156 million for the 2014-2016 annual reconciliations and \$42 million related to significant one-time events including \$31 million of deferred storm costs, \$9 million of Constellation merger and integration related costs and \$2 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.
- (c) Includes at Exelon and PHI the regulatory asset recorded at Exelon and 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.
- (d) 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.
- (e) 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 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 supply contracts through their respective rate making processes.
- (f) As of March 31, 2016, ComEd's regulatory asset of \$56 million included \$18 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 March 31, 2016, ComEd's regulatory liability of \$43 million included \$17 million related to over-recovered energy costs and \$26 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.
- (g) As of March 31, 2016, BGE's regulatory asset of \$38 million included \$5 million of costs associated with transmission costs recoverable through its FERC approved formula rate and \$33 million related to under-recovered electric energy costs. As of March 31, 2016, BGE's

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regulatory liability of \$15 million related to \$2 million of over-recovered transmission costs and \$14 million of over-recovered natural gas costs, offset by \$1 million of abandonment costs to be



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

- recovered upon FERC approval. 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.
- (h) Represents the electric and gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of March 31, 2016, BGE had a regulatory asset of \$31 million related to under-recovered electric revenue decoupling and a regulatory asset of \$5 million related to under-recovered natural gas 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.
- (i) Represents the regulatory asset recorded at Exelon and PHI for the difference between the carrying value and fair value of alternative energy credits at Pepco, DPL and ACE recorded at Exelon and PHI that are recoverable through the rate making process.
- (j) 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 which was eliminated at PHI as part of acquisition accounting.
- (k) As of March 31, 2016, PECO's regulatory liability of \$69 million included \$36 million related to the DSP program, \$26 million related to the over-recovered natural gas costs under the PGC, \$3 million related to over-recovered electric transmission costs and \$4 million related to over-recovered non-bypassable transmission service charges. As of December 31, 2015, PECO's regulatory asset of \$1 million related to under-recovered non-bypassable transmission service charges. As of December 31, 2015, PECO's regulatory liability of \$60 million included \$35 million related to 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.
- (l) As of March 31, 2016, DPL's regulatory liability of \$25 million included \$6 million related to over-recovered natural gas costs under the GCR mechanism, \$7 million of over-recovered electric energy costs, and \$12 million of over-recovered transmission 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.
- (m) As of March 31, 2016, Pepco's regulatory asset of \$5 million included \$4 million of transmission costs recoverable through its FERC approved formula rate and \$1 million of under-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.
- (n) As of March 31, 2016, DPL's regulatory asset of \$6 million related to transmission costs recoverable through its FERC approved formula rate. 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.
- (o) As of March 31, 2016, ACE's regulatory asset of \$13 million included \$1 million of transmission costs recoverable through its FERC approved formula rate and \$12 million of under-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.
- (p) As of March 31, 2016, Pepco's regulatory liability of \$25 million included \$15 million of over-recovered transmission costs and \$10 million of over-recovered electric energy 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.
- (q) As of March 31, 2016, ACE's regulatory liability of \$10 million related to over-recovered transmission costs. As of December 31, 2015, ACE's regulatory liability of \$8 million related to over-recovered transmission costs.
- (r) Represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout Pepco's and DPL's service territories that are recoverable from customers. AMI has not been approved by the NJBPU for ACE in New Jersey. PHI generally is deferring carrying charges on these regulatory assets.

**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

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

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 and ACE are required to purchase receivables at face value and are permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of March 31, 2016 and December 31, 2015.

As of March 31, 2016	Exelon	ComEd	PECO	BGE	Successor			
					PHI	Pepco	DPL	ACE
Purchased receivables <sup>(c)</sup>	\$ 343	\$ 96	\$ 75	\$ 66	\$ 106	\$ 77	\$ 11	\$ 18
Allowance for uncollectible accounts <sup>(a)</sup>	(38)	(16)	(8)	(8)	(6)	(4)		(2)
Purchased receivables, net	\$ 305	\$ 80	\$ 67	\$ 58	\$ 100	\$ 73	\$ 11	\$ 16

  

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

- (a) For ComEd, BGE, Pepco, DPL and ACE, 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 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.

**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 at March 31, 2016. 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. After reflecting the impairment charges, Generation has \$63 million of Upstream assets remaining on its Consolidated Balance Sheets at March 31, 2016. 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.

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The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including commodity prices and production volumes, projected capital and maintenance expenditures and discount rates.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****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. Implications of Potential Early Plant Retirements (Exelon and Generation)**

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions in New York and Illinois such as the recently proposed Zero Emission Standard element of the Next Generation Energy Plan (NGEP) or Low Carbon Portfolio Standard (LCPS) legislation in Illinois and Clean Energy Standard (CES) in New York, the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules.

In 2015, 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 auction to be 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. The results of the 2019-2020 PJM capacity auction will be available on May 24, 2016.

On May 6, 2016 Exelon and Generation announced intentions to shut down the Clinton nuclear plant on June 1, 2017 and Quad Cities nuclear plant on June 1, 2018 if Illinois does not pass adequate legislation by May 31, 2016 and if Quad Cities does not clear the 2019-2020 PJM capacity auction. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. The approved RSSA requires Ginna to continue operating through the RSSA term expiring in March 2017. There remains an increased risk that, for economic reasons, Ginna could be retired before the end of its operating license period in 2029 if an adequate regulatory or legislative solution is not adopted in New York. Refer to Note 5 Regulatory Matters for additional discussion on the Ginna RSSA.

In response to a decision to early retire one or more nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, contract termination fees, accelerated amortization of plant specific nuclear fuel costs, employee-related costs (i.e. severance, relocation, retention, etc.), accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of nuclear decommissioning trust funds. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown.

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

The following table provides the balance sheet amounts as of March 31, 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 their current economic valuations and other factors.

(in millions)	Quad Cities	Clinton	Ginna	Total
<b>Asset Balances</b>				
Materials and supplies inventory	\$ 47	\$ 58	\$ 30	\$ 135
Nuclear fuel inventory, net	213	95	54	362
Completed plant, net	1,014	574	127	1,715
Construction work in progress	28	11	11	50
<b>Liability Balances</b>				
Asset retirement obligation	(706)	(407)	(651)	(1,764)
NRC License Renewal Term	2032	2046 <sup>(a)</sup>	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

The precise timing of an early retirement date, and resulting financial statement impact, may be affected by a number of factors, including the 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 and just prior to its next scheduled nuclear refueling outage date in that year.

**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 March 31, 2016 and December 31, 2015:

*Exelon*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 3,643	\$ 3	\$ 3,640	\$	\$ 3,643
Long-term debt (including amounts due within one year) <sup>(a)</sup>	31,372	1,132	29,577	2,135	32,844
Long-term debt to financing trusts <sup>(b)</sup>	641			670	670
SNF obligation	1,022		817		817

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 536	\$ 3	\$ 533	\$	\$ 536

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Long-term debt (including amounts due within one year) <sup>(a)</sup>	25,145	931	23,644	1,349	25,924
Long-term debt to financing trusts <sup>(b)</sup>	641			673	673
SNF obligation	1,021		818		818

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*Generation*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 1,529	\$	\$ 1,529	\$	\$ 1,529
Long-term debt (including amounts due within one year) <sup>(a)</sup>	9,052		7,539	1,549	9,088
SNF obligation	1,022		817		817

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

*ComEd*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 643	\$	\$ 643	\$	\$ 643
Long-term debt (including amounts due within one year) <sup>(a)</sup>	6,510		7,357		7,357
Long-term debt to financing trusts <sup>(b)</sup>	205			207	207

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

*PECO*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 2,581	\$	\$ 2,900	\$	\$ 2,900
Long-term debt to financing trusts	184			196	196

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	Carrying Amount	Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 2,580	\$	\$ 2,786	\$	\$ 2,786
Long-term debt to financing trusts	184			195	195



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

*BGE*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 153	\$ 3	\$ 150	\$	\$ 153
Long-term debt (including amounts due within one year) <sup>(a)</sup>	1,859		2,119		2,119
Long-term debt to financing trusts <sup>(b)</sup>	252			267	267

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

*PHI*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
<i>Successor</i> Short-term liabilities	\$ 1,317	\$	\$ 1,317	\$	\$ 1,317
Long-term debt (including amounts due within one year)	6,132		5,540	586	6,126

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
<i>Predecessor</i> Short-term liabilities	\$ 958	\$	\$ 958	\$	\$ 958
Long-term debt (including amounts due within one year) <sup>(a)</sup>	5,279		5,231	586	5,817
Preferred stock	183			183	183

*Pepco*

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 2,352	\$	\$ 2,876	\$	\$ 2,876

	Carrying Amount	December 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 64	\$	\$ 64	\$	\$ 64

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Long-term debt (including amounts due within one year) <sup>(a)</sup>	2,351	2,673	2,673
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(Dollars in millions, except per share data, unless otherwise noted)

DPL

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 75	\$	\$ 75	\$	\$ 75
Long-term debt (including amounts due within one year) <sup>(a)</sup>	1,265		1,238	103	1,341

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

ACE

	Carrying Amount	March 31, 2016 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year) <sup>(a)</sup>	\$ 1,191	\$	\$ 1,081	\$ 288	\$ 1,369

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

(a) Includes unamortized debt issuance costs of \$179 million, \$72 million, \$37 million, \$14 million, \$9 million, \$31 million, \$10 million, and \$6 million for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of March 31, 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 of \$7 million, \$1 million, and \$6 million for Exelon, ComEd and BGE, respectively, as of March 31, 2016 and December 31, 2015.

*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

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

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.

*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.

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

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 three months ended March 31, 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.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2016 and December 31, 2015:

As of March 31, 2016	Generation					Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
<b>Assets</b>										
Cash equivalents	\$ 130	\$	\$	\$	\$ 130	\$ 721	\$	\$	\$	\$ 721
NDT fund investments										
Cash equivalents <sup>(a)</sup>	266	11			277	266	11			277
Equities	3,273	21	1	1,875	5,170	3,273	21	1	1,875	5,170
Fixed income										
Corporate debt		1,868	243		2,111		1,868	243		2,111
U.S. Treasury and agencies	1,402	13			1,415	1,402	13			1,415
Foreign governments		45			45		45			45
State and municipal debt		285			285		285			285
Other <sup>(b)</sup>		64		376	440		64		376	440
Fixed income subtotal	1,402	2,275	243	376	4,296	1,402	2,275	243	376	4,296
Middle market lending			440		440			440		440
Private equity				130	130				130	130
Real estate				40	40				40	40
Other				190	190				190	190
NDT fund investments subtotal <sup>(c)</sup>	4,941	2,307	684	2,611	10,543	4,941	2,307	684	2,611	10,543
Pledged assets for Zion Station decommissioning										
Cash equivalents	35				35	35				35
Equities	1	7			8	1	7			8
Fixed income										
U.S. Treasury and agencies	3	2			5	3	2			5
Corporate debt		25			25		25			25

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Fixed income subtotal	3	27			30	3	27			30
Middle market lending			25	85	110			25	85	110
Pledged assets for Zion Station decommissioning subtotal <sup>(d)</sup>	39	34	25	85	183	39	34	25	85	183

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of March 31, 2016	Generation				Total	Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling		Level 1	Level 2	Level 3	Not subject to leveling	
<b>Rabbi trust investments</b>										
Cash equivalents	9				9	83				83
Mutual funds	17				17	46				46
Fixed income							14			14
Life insurance contracts		16			16		60	20		80
<b>Rabbi trust investments subtotal</b>	<b>26</b>	<b>16</b>			<b>42</b>	<b>129</b>	<b>74</b>	<b>20</b>		<b>223</b>
<b>Commodity derivative assets</b>										
Economic hedges	1,591	4,849	1,788		8,228	1,591	4,849	1,788		8,228
Proprietary trading	31	82	30		143	31	82	30		143
Effect of netting and allocation of collateral <sup>(e)</sup>	(1,739)	(3,997)	(675)		(6,411)	(1,739)	(3,997)	(675)		(6,411)
<b>Commodity derivative assets subtotal</b>	<b>(117)</b>	<b>934</b>	<b>1,143</b>		<b>1,960</b>	<b>(117)</b>	<b>934</b>	<b>1,143</b>		<b>1,960</b>
<b>Interest rate and foreign currency derivative assets</b>										
Derivatives designated as hedging instruments							42			42
Economic hedges		20			20		20			20
Proprietary trading	11	2			13	11	2			13
Effect of netting and allocation of collateral	(4)	(5)			(9)	(4)	(5)			(9)
<b>Interest rate and foreign currency derivative assets subtotal</b>	<b>7</b>	<b>17</b>			<b>24</b>	<b>7</b>	<b>59</b>			<b>66</b>
<b>Other investments</b>			36		36			36		36
<b>Total assets</b>	<b>5,026</b>	<b>3,308</b>	<b>1,888</b>	<b>2,696</b>	<b>12,918</b>	<b>5,720</b>	<b>3,408</b>	<b>1,908</b>	<b>2,696</b>	<b>13,732</b>
<b>Liabilities</b>										
<b>Commodity derivative liabilities</b>										
Economic hedges	(2,053)	(4,688)	(885)		(7,626)	(2,054)	(4,688)	(1,150)		(7,892)
Proprietary trading	(28)	(79)	(37)		(144)	(28)	(79)	(37)		(144)
Effect of netting and allocation of collateral <sup>(e)</sup>	2,089	4,535	826		7,450	2,090	4,535	826		7,451
<b>Commodity derivative liabilities subtotal</b>	<b>8</b>	<b>(232)</b>	<b>(96)</b>		<b>(320)</b>	<b>8</b>	<b>(232)</b>	<b>(361)</b>		<b>(585)</b>
<b>Interest rate and foreign currency derivative liabilities</b>										
Derivatives designated as hedging instruments		(20)			(20)		(23)			(23)
Economic hedges		(8)			(8)		(8)			(8)
Proprietary trading	(11)				(11)	(11)				(11)
Effect of netting and allocation of collateral	11	5			16	11	5			16
<b>Interest rate and foreign currency derivative liabilities subtotal</b>		<b>(23)</b>			<b>(23)</b>		<b>(26)</b>			<b>(26)</b>
<b>Deferred compensation obligation</b>		(30)			(30)		(131)			(131)



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<b>Total liabilities</b>	8	(285)	(96)	(373)	8	(389)	(361)	(742)		
<b>Total net assets</b>	\$ 5,034	\$ 3,023	\$ 1,792	\$ 2,696	\$ 12,545	\$ 5,728	\$ 3,019	\$ 1,547	\$ 2,696	\$ 12,990

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of December 31, 2015	Generation				Total	Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling		Level 1	Level 2	Level 3	Not subject to leveling	
<b>Assets</b>										
Cash equivalents	\$ 104	\$	\$	\$	\$ 104	\$ 5,766	\$	\$	\$	\$ 5,766
NDT fund investments										
Cash equivalents <sup>(a)</sup>	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 <sup>(b)</sup>		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 <sup>(c)</sup>	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 <sup>(d)</sup>	7	71	22	105	205	7	71	22	105	205
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 <sup>(e)</sup>	(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

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Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments										
Economic hedges		20		20			25			25
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
<b>Total assets</b>	4,679	3,473	1,898	2,765	12,815	10,372	3,521	1,898	2,765	18,556

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of December 31, 2015	Generation				Total	Exelon				
	Level 1	Level 2	Level 3	Not subject to leveling		Level 1	Level 2	Level 3	Not subject to leveling	
<b>Liabilities</b>										
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 <sup>(e)</sup>	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)
<b>Total liabilities</b>	25	(265)	(122)		(362)	25	(334)	(369)		(678)
<b>Total net assets</b>	\$ 4,704	\$ 3,208	\$ 1,776	\$ 2,765	\$ 12,453	\$ 10,397	\$ 3,187	\$ 1,529	\$ 2,765	\$ 17,878

- (a) Includes \$38 million and \$52 million of cash received from outstanding repurchase agreements at March 31, 2016 and December 31, 2015, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (c) below.
- (b) Includes derivative instruments of \$(11) million and \$(8) million, which have a total notional amount of \$1,155 million and \$1,236 million at March 31, 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.
- (c) Excludes net liabilities of \$(17) million and \$(3) million at March 31, 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.
- (d) Excludes net assets of \$0 million and \$1 million at March 31, 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.
- (e) Collateral posted to/(received) from counterparties totaled \$350 million, \$538 million and \$151 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*ComEd, PECO and BGE*

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

As of March 31, 2016	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$	\$	\$	\$	\$ 3	\$	\$	\$ 3	\$ 43	\$	\$	\$ 43
Rabbi trust investments												
Mutual funds					8			8	4			4
Life insurance contracts						11		11				
Rabbi trust investments subtotal					8	11		19	4			4
<b>Total assets</b>					11	11		22	47			47
<b>Liabilities</b>												
Deferred compensation obligation			(8)	(8)			(12)	(12)		(3)		(3)
Mark-to-market derivative liabilities <sup>(a)</sup>			(265)	(265)								
<b>Total liabilities</b>			(8)	(273)			(12)	(12)		(3)		(3)
<b>Total net assets (liabilities)</b>	\$	\$	(8)	\$ (273)	\$ 11	\$ (1)	\$	\$ 10	\$ 47	\$ (3)	\$	\$ 44

As of December 31, 2015	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$ 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
<b>Total assets</b>	29			29	279	12		291	29			29
<b>Liabilities</b>												
Deferred compensation obligation			(8)	(8)			(12)	(12)		(4)		(4)
Mark-to-market derivative liabilities <sup>(a)</sup>			(247)	(247)								
<b>Total liabilities</b>			(8)	(255)			(12)	(12)		(4)		(4)
<b>Total net assets (liabilities)</b>	\$ 29	\$ (8)	\$ (247)	\$ (226)	\$ 279	\$	\$	\$ 279	\$ 29	\$ (4)	\$	\$ 25

- (a) The Level 3 balance consists of the current and noncurrent liability of \$26 million and \$239 million, respectively, at March 31, 2016, and \$23 million and \$224 million, respectively, at December 31, 2015, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*PHI, Pepco, DPL and ACE*

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

PHI	<i>Successor</i>				<i>Predecessor</i>			
	As of March 31, 2016				As of December 31, 2015			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>								
Cash equivalents	\$ 168	\$	\$	\$ 168	\$ 42	\$	\$	\$ 42
Derivative asset							18	18
Rabbi trust investments								
Cash equivalents	73			73	12			12
Fixed income		14		14		15		15
Life insurance contracts		22	20	42		27	19	46
Rabbi trust investments subtotal	73	36	20	129	12	42	19	73
<b>Total assets</b>	<b>241</b>	<b>36</b>	<b>20</b>	<b>297</b>	<b>54</b>	<b>42</b>	<b>37</b>	<b>133</b>
<b>Liabilities</b>								
Deferred compensation obligation		(30)		(30)		(30)		(30)
Mark-to-market derivative liabilities <sup>(a)</sup>	(1)			(1)	(2)			(2)
Effect of netting and allocation of collateral	1			1	2			2
Mark-to-market derivative liabilities subtotal								
<b>Total liabilities</b>		<b>(30)</b>		<b>(30)</b>		<b>(30)</b>		<b>(30)</b>
<b>Total net assets</b>	<b>\$ 241</b>	<b>\$ 6</b>	<b>\$ 20</b>	<b>\$ 267</b>	<b>\$ 54</b>	<b>\$ 12</b>	<b>\$ 37</b>	<b>\$ 103</b>

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of March 31, 2016	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$ 19	\$	\$	\$ 19	\$	\$	\$	\$	\$ 148	\$	\$	\$ 148
Rabbi trust investments												
Cash equivalents	43			43								
Fixed income		14		14								
Life insurance contracts		22	20	42								
Rabbi trust investments subtotal	43	36	20	99								
<b>Total assets</b>	<b>62</b>	<b>36</b>	<b>20</b>	<b>118</b>					<b>148</b>			<b>148</b>
<b>Liabilities</b>												
Deferred compensation obligation		(5)		(5)		(1)		(1)				
Mark-to-market derivative liabilities <sup>(a)</sup>					(1)			(1)				
Effect of netting and allocation of collateral					1			1				
Mark-to-market derivative liabilities subtotal												
<b>Total liabilities</b>		<b>(5)</b>		<b>(5)</b>		<b>(1)</b>		<b>(1)</b>				
<b>Total net assets (liabilities)</b>	<b>\$ 62</b>	<b>\$ 31</b>	<b>\$ 20</b>	<b>\$ 113</b>	<b>\$</b>	<b>\$ (1)</b>	<b>\$</b>	<b>\$ (1)</b>	<b>\$ 148</b>	<b>\$</b>	<b>\$</b>	<b>\$ 148</b>

As of December 31, 2015	Pepco				DPL				ACE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
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								
<b>Total assets</b>	<b>13</b>	<b>38</b>	<b>19</b>	<b>70</b>					<b>30</b>			<b>30</b>
<b>Liabilities</b>												
Deferred compensation obligation		(6)		(6)		(1)		(1)				
Mark-to-market derivative liabilities <sup>(a)</sup>					(2)			(2)				
Effect of netting and allocation of collateral					2			2				
Mark-to-market derivative liabilities subtotal												



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<b>Total liabilities</b>			(6)	(6)	(1)	(1)						
<b>Total net assets (liabilities)</b>	\$ 13	\$ 32	\$ 19	\$ 64	\$	\$ (1)	\$	\$ (1)	\$ 30	\$	\$	\$ 30

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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2016 and 2015:

Three Months Ended March 31, 2016	NDT Fund Investments	Pledged Assets for Zion Station decommissioning	Generation		Total Generation	ComEd	Successor PHI <sup>(a)</sup>	Eliminated in Consolidation	Exelon
			Mark-to- Market Derivatives	Other Investments		Mark-to- Market Derivatives <sup>(b)</sup>	Life Insurance Contracts		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		(6) <sup>(c)</sup>		(4)				(4)
Included in noncurrent payables to affiliates	4				4			(4)	
Included in payable for Zion Station decommissioning		2			2				2
Included in regulatory assets/liabilities						(18)		4	(14)
Change in collateral			(50)		(50)				(50)
Purchases, sales, issuances and settlements									
Purchases	34	1	59	3	97				97
Sales			(2)		(2)				(2)
Settlements	(26)				(26)				(26)
Transfers into Level 3			2		2				2
Transfers out of Level 3			(7)		(7)				(7)
Balance as of March 31, 2016	\$ 684	\$ 25	\$ 1,047	\$ 36	\$ 1,792	\$ (265)	\$ 20	\$	\$ 1,547

The amount of total gains included  
in income attributed to the change in  
unrealized gains related to assets  
and liabilities as of March 31, 2016

\$ 1	\$	\$ 219	\$	\$ 220	\$	\$	\$	\$ 220
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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Three Months Ended March 31, 2015	NDT Fund Investment	Pledged Assets for Zion Station Decommissioning	Generation		Total Generation	ComEd		Exelon Total
			Mark-to- Market Derivatives	Other Investments		Mark-to- Market Derivatives <sup>(b)</sup>	Eliminated in Consolidation	
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	2		(32) <sup>(c)</sup>		(30)			(30)
Included in other comprehensive income								
Included in noncurrent payables to affiliates	10				10		(10)	
Included in payable for Zion Station decommissioning		3			3			3
Included in regulatory assets						(34)	10	(24)
Change in collateral			12		12			12
Purchases, sales, issuances and settlements								
Purchases	28		41		69			69
Sales	(8)	(9)			(17)			(17)
Settlements	(29)				(29)			(29)
Transfers into Level 3	4				4			4
Transfers out of Level 3			(5)		(5)			(5)
Balance as of March 31, 2015	\$ 612	\$ 44	\$ 1,066	\$ 3	\$ 1,725	\$ (241)	\$	\$ 1,484
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities as of March 31, 2015	\$ 1	\$	\$ 180	\$	\$ 181	\$	\$	\$ 181

- (a) Successor period represents activity from March 24, 2016 through March 31, 2016. See tables below for PHI's predecessor periods, as well as activity for Pepco and DPL for the three months ended March 31, 2016 and 2015.
- (b) Includes \$25 million of decreases in fair value and realized losses due to settlements of \$7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2016. Includes \$36 million of decreases in fair value and realized losses due to settlements of \$2 million for the three months ended March 31, 2015.
- (c) Includes a reduction for the reclassification of \$225 million and \$212 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three months ended March 31, 2016 and 2015, respectively.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	January 1, 2016 to March 23, 2016		<i>Predecessor</i> Three Months Ended March 31, 2015	
	Preferred Stock	Life Insurance Contracts	Preferred Stock	Life Insurance Contracts
<b>PHI</b>				
Beginning Balance	\$ 18	\$ 19	\$ 3	\$ 19
Total realized / unrealized gains (losses)				
Included in net income	(18)	1		1
Purchases, sales, issuances and settlements				
Settlements				(1)
Ending Balance	\$	\$ 20	\$ 3	\$ 19
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	\$	\$ 1	\$	\$ 1

	Three Months Ended March 31, 2016		Three Months Ended March 31, 2015	
	Pepco Life Insurance Contracts	DPL Life Insurance Contracts	Pepco Life Insurance Contracts	DPL Life Insurance Contracts
Balance as of December 31	\$ 19	\$	\$ 18	\$ 1
Total realized / unrealized gains (losses)				
Included in net income	1		1	
Purchases, sales, issuances and settlements				
Settlements				(1)
Balance as of March 31	\$ 20	\$	\$ 19	\$
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities for the period	\$ 1	\$	\$ 1	\$

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2016 and 2015:

	Operating Revenues	Generation Purchased Power and Fuel	Other, net <sup>(b)</sup>	Operating Revenues	Exelon Purchased Power and Fuel	Other, net <sup>(b)</sup>
Total gains (losses) included in net income for the three months ended March 31, 2016	49	(55)	2	49	(55)	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2016	254	(35)	1	254	(35)	1

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Operating Revenues	Generation Purchased Power and Fuel	Other, net <sup>(b)</sup>	Operating Revenues	Exelon Purchased Power and Fuel	Other, net <sup>(b)</sup>
Total gains (losses) included in net income for the three months ended March 31, 2015	(10)	(22)	2	(10)	(22)	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2015	169	11	1	169	11	1

	Predecessor PHI January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015	Other, net	Three Months Ended March 31, 2016	Pepco Three Months Ended March 31, 2015
Total (losses) gains included in net income	\$ (17)	\$ 1		\$ 1	\$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held	1	1		1	1

(a) Successor period represents activity for the period of March 24, 2016 through March 31, 2016.

(b) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

**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.

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

*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 preferred 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, balanced 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.

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

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 March 31, 2016, Generation has outstanding commitments to invest in middle market lending, private equity investments and real estate investments of approximately \$142 million, \$42 million, and \$135 million, respectively. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

*Concentrations of Credit Risk.* Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of March 31, 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 March 31, 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 and DPL).* 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

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

unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants derivatives are 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 and DPL).* 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, PECO, 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



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

instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

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

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately \$2.82 and \$0.25 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

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

assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

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

Type of trade		Fair Value at March 31, 2016	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Exelon and Generation) <sup>(a)(c)</sup>		\$ 903	Discounted Cash Flow	Forward power price	\$7 \$88
				Forward gas price	\$0.58 \$7.67
				Option Model	Volatility percentage
Mark-to-market derivatives Proprietary trading (Exelon and Generation) <sup>(a)(c)</sup>		\$ (7)	Discounted Cash Flow	Forward power price	\$9 \$83
Mark-to-market derivatives (Exelon and ComEd)		\$ (265)	Discounted Cash Flow	Forward heat rate <sup>(b)</sup>	9x 10x
				Marketability reserve	3.5% 7%
				Renewable factor	88% 129%

(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 \$151 million as of March 31, 2016.

Type of trade		Fair Value at December 31, 2015	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Exelon and Generation) <sup>(a)(c)</sup>		\$ 857	Discounted Cash Flow	Forward power price	\$11 \$88
				Forward gas price	\$1.18 \$8.95
				Option Model	Volatility percentage
Mark-to-market derivatives Proprietary trading (Exelon and Generation) <sup>(a)(c)</sup>		\$ (7)	Discounted Cash Flow	Forward power price	\$13 \$78
Mark-to-market derivatives (Exelon and ComEd)		\$ (247)	Discounted Cash Flow	Forward heat rate <sup>(b)</sup>	9x 10x

Marketability reserve	3.5%	7%
Renewable factor	87%	128%

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

- (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 held on level three positions of \$201 million as of December 31, 2015.

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, Generation, PECO, PHI, Pepco and DPL)* 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.

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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****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. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 23 Commitments and Contingencies of the Exelon 2015 Form 10-K. 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.

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

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of March 31, 2016, the proportion of expected generation hedged for the major reportable segments is 96%-99%, 69%-72% and 37%-40% 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 2015 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 2015 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 30% 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 MDPS. 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

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

return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

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

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

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

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL's Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up versus the forecast on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL's firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers' exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to fifty percent (50%) of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The fifty percent (50%) hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its Gas Hedging Program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments.

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

Because of the DPSC-approved fuel adjustment clause for DPL's derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL's physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

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

*Proprietary Trading.* Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 1,220 GWhs and 1,808 GWhs for the three months ended March 31, 2016 and 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 March 31, 2016, Exelon had \$800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had \$1,287 million and \$687 million of notional amounts of floating-to-fixed hedges outstanding, respectively. 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 \$1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 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 March 31, 2016.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Description	Generation				Subtotal	Exelon	Exelon
	Derivatives Designated as Hedging Instruments		Proprietary Trading <sup>(a)</sup>	Collateral and Netting <sup>(b)</sup>		Corporate Derivatives Designated as Hedging Instruments	
Mark-to-market derivative assets (current assets)	\$	\$ 10	\$ 8	\$ (5)	\$ 13	\$	\$ 13
Mark-to-market derivative assets (noncurrent assets)		10	5	(4)	11	42	53
<b>Total mark-to-market derivative assets</b>		<b>20</b>	<b>13</b>	<b>(9)</b>	<b>24</b>	<b>42</b>	<b>66</b>
Mark-to-market derivative liabilities (current liabilities)	(8)	(3)	(6)	9	(8)		(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(12)	(5)	(5)	7	(15)	(3)	(18)
<b>Total mark-to-market derivative liabilities</b>	<b>(20)</b>	<b>(8)</b>	<b>(11)</b>	<b>16</b>	<b>(23)</b>	<b>(3)</b>	<b>(26)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ (20)</b>	<b>\$ 12</b>	<b>\$ 2</b>	<b>\$ 7</b>	<b>\$ 1</b>	<b>\$ 39</b>	<b>\$ 40</b>

(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.

**Table of Contents****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 interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2015:

Description	Generation				Subtotal	Exelon	Exelon
	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading <sup>(a)</sup>	Collateral and Netting <sup>(b)</sup>		Corporate Derivatives Designated as Hedging Instruments	
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.

*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 March 31,

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	<b>Income Statement Location</b>	<b>2016 Gain (Loss) on Swaps</b>	<b>2015 Gain (Loss) on Swaps</b>	<b>2016 Gain (Loss) on Borrowings</b>	<b>2015 Gain (Loss) on Borrowings</b>
Generation	Interest expense <sup>(a)</sup>	\$	\$ (1)	\$	\$
Exelon	Interest expense	17	9	(15)	(7)

(a) For the three months ended March 31, 2015, the loss on Generation swaps included \$1 million realized in earnings with an immaterial amount excluded from hedge effectiveness testing.

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

At March 31, 2016, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of \$800 million, with a derivative asset of \$42 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 months ended March 31, 2016 and 2015, the impact on the results of operations as a result of ineffectiveness from fair value hedges was a \$2 million gain for each period.

*Cash Flow Hedges.* During the first quarter of 2016, Exelon entered into \$600 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated issuance of debt. The swaps are designated as cash flow hedges. At March 31, 2016, Exelon had a \$3 million derivative liability related to the swaps.

During the first quarter of 2016, Exelon entered into \$100 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 swap is 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. See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

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 \$499 million as of March 31, 2016 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At March 31, 2016, the subsidiary had a \$17 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 \$189 million as of March 31, 2016 and expire in 2020. The swaps are designated as cash flow hedges. At March 31, 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 months ended March 31, 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.

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

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 March 31, 2016, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and \$137 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 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 March 31, 2016 and December 31, 2015, \$1 million and \$3 million of cash collateral 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.

**Table of Contents****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 March 31, 2016:

Derivatives	Generation Collateral				ComEd	DPL Collateral			Successor PHI	Exelon	Total Derivatives
	Economic Hedges	Proprietary Trading	and Netting <sup>(a)</sup>	Subtotal <sup>(b)</sup>	Economic Hedges <sup>(c)</sup>	Economic Hedges <sup>(d)</sup>	and Netting <sup>(a)</sup>	Subtotal	Subtotal		
Mark-to-market derivative assets (current assets)	\$ 5,851	\$ 113	\$ (4,792)	\$ 1,172	\$	\$	\$	\$	\$	\$ 1,172	
Mark-to-market derivative assets (noncurrent assets)	2,377	30	(1,619)	788						788	
<b>Total mark-to-market derivative assets</b>	<b>8,228</b>	<b>143</b>	<b>(6,411)</b>	<b>1,960</b>						<b>1,960</b>	
Mark-to-market derivative liabilities (current liabilities)	(5,570)	(104)	5,505	(169)	(26)	(1)	1			(195)	
Mark-to-market derivative liabilities (noncurrent liabilities)	(2,056)	(40)	1,945	(151)	(239)					(390)	
<b>Total mark-to-market derivative liabilities</b>	<b>(7,626)</b>	<b>(144)</b>	<b>7,450</b>	<b>(320)</b>	<b>(265)</b>	<b>(1)</b>	<b>1</b>			<b>(585)</b>	
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ 602</b>	<b>\$ (1)</b>	<b>\$ 1,039</b>	<b>\$ 1,640</b>	<b>\$ (265)</b>	<b>\$ (1)</b>	<b>\$ 1</b>	<b>\$</b>	<b>\$</b>	<b>\$ 1,375</b>	

- (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 \$303 million and \$146 million, respectively, and current and noncurrent liabilities are shown net of collateral of \$410 million and \$180 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was \$1,039 million at March 31, 2016.
- (c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.
- (d) Represents natural gas futures purchased as part by DPL as part of a natural gas hedging program approved by the DPSC.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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

Description	Generation				ComEd	Exelon	DPL			Predecessor			
	Economic Hedges	Proprietary Trading	and Netting <sup>(a)</sup>	Subtotal <sup>(b)</sup>			Economic Hedges <sup>(c)</sup>	Total Derivatives	Economic Hedges <sup>(e)</sup>	and Netting <sup>(a)</sup>	Subtotal	PHI Corporate	PHI
												Other <sup>(d)</sup>	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							
<b>Total mark-to-market derivative assets</b>	<b>7,096</b>	<b>130</b>	<b>(5,157)</b>	<b>2,069</b>		<b>2,069</b>				<b>18</b>	<b>18</b>		
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)							
<b>Total mark-to-market derivative liabilities</b>	<b>(6,580)</b>	<b>(127)</b>	<b>6,391</b>	<b>(316)</b>	<b>(247)</b>	<b>(563)</b>	<b>(2)</b>	<b>2</b>					
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ 516</b>	<b>\$ 3</b>	<b>\$ 1,234</b>	<b>\$ 1,753</b>	<b>\$ (247)</b>	<b>\$ 1,506</b>	<b>\$ (2)</b>	<b>\$ 2</b>	<b>\$</b>	<b>\$ 18</b>	<b>\$ 18</b>		

- (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 as part by DPL as part of a natural gas hedging program approved by the DPSC.

**Table of Contents****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 three months ended March 31, 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.

	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
<b>Three Months Ended March 31, 2016</b>			
Accumulated OCI derivative loss at December 31, 2015		\$ (21)	\$ (19)
Effective portion of changes in fair value		(8)	(10)
Reclassifications from AOCI to net income	Interest Expense	3 <sup>(a)</sup>	3 <sup>(a)</sup>
Accumulated OCI derivative loss at March 31, 2016		\$ (26)	\$ (26)

	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
<b>Three Months Ended March 31, 2015</b>			
Accumulated OCI derivative loss at December 31, 2014		\$ (18)	\$ (28)
Effective portion of changes in fair value		(6)	(11)
Reclassifications from AOCI to net income	Other, net		16 <sup>(b)</sup>
Reclassifications from AOCI to net income	Interest Expense	3	3
Reclassifications from AOCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative loss at March 31, 2015		\$ (23)	\$ (22)

(a) Amount is net of related income tax expense of \$2 million for both the three months ended March 31, 2016.

(b) Amount is net of related income tax benefit of \$10 million for the three months ended March 31, 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 three months ended March 31, 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



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currencies other than U.S. Dollars. For the three months ended March 31, 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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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.

	<b>Operating Revenues</b>	<b>Generation Purchased Power and Fuel</b>	<b>Total</b>	<b>Exelon Total</b>
<b>Three Months Ended March 31, 2016</b>				
Change in fair value of commodity positions	\$ 279	\$ (127)	\$ 152	\$ 152
Reclassification to realized at settlement of commodity positions	(211)	167	(44)	(44)
Net commodity mark-to-market gains (losses)	68	40	108	108
Change in fair value of treasury positions	(3)		(3)	(3)
Reclassification to realized at settlement of treasury positions	(2)		(2)	(2)
Net treasury mark-to-market gains (losses)	(5)		(5)	(5)
Net mark-to-market gains (losses)	\$ 63	\$ 40	\$ 103	\$ 103

	<b>Operating Revenues</b>	<b>Generation Purchased Power and Fuel</b>	<b>Total</b>	<b>Exelon Corporate Interest Expense</b>	<b>Exelon Total</b>
<b>Three Months Ended March 31, 2015</b>					
Change in fair value of commodity positions	\$ 164	\$ (79)	\$ 85	\$	\$ 85
Reclassification to realized at settlement of commodity positions	(21)	87	66		66
Net commodity mark-to-market gains (losses)	143	8	151		151
Change in fair value of treasury positions	13		13	(78)	(65)
Reclassification to realized at settlement of treasury positions	(2)		(2)		(2)
Net treasury mark-to-market gains (losses)	11		11	(78)	(67)
Net mark-to-market gains (losses)	\$ 154	\$ 8	\$ 162	\$ (78)	\$ 84

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

*Proprietary Trading Activities (Exelon and Generation).* For the three months ended March 31, 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.

	Location on Income Statement	Three Months Ended March 31,	
		2016	2015
Change in fair value of commodity positions	Operating Revenues	\$ 7	\$ 1
Reclassification to realized at settlement of commodity positions	Operating Revenues	(3)	2
Net commodity mark-to-market gains (losses)	Operating Revenues	4	3
Change in fair value of treasury positions	Operating Revenues	(2)	4
Reclassification to realized at settlement of treasury positions	Operating Revenues	1	(4)
Net treasury mark-to-market gains (losses)	Operating Revenues	(1)	
Total net mark-to-market gains (losses)	Operating Revenues	\$ 3	\$ 3

**Credit Risk (All Registrants)**

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

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

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2016. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. **QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.** Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of \$19 million, \$37 million, \$35 million, \$36 million, \$11 million, and \$8 million as of March 31, 2016, respectively.

Rating as of March 31, 2016	Total Exposure Before			Number of Net Exposure of Counterparties Greater than 10%	
	Credit Collateral	Credit Collateral <sup>(a)</sup>	Net Exposure	of Net Exposure	of Net Exposure
Investment grade	\$ 1,276	\$ 58	\$ 1,218	1	\$ 436
Non-investment grade	71	32	39		
No external ratings					
Internally rated investment grade	516	1	515		
Internally rated non-investment grade	101	4	97		
Total	\$ 1,964	\$ 95	\$ 1,869	1	\$ 436

Net Credit Exposure by Type of Counterparty	As of March 31, 2016
Financial institutions	\$ 116
Investor-owned utilities, marketers, power producers	781
Energy cooperatives and municipalities	909
Other	63
Total	\$ 1,869

(a) As of March 31, 2016, credit collateral held from counterparties where Generation had credit exposure included \$8 million of cash and \$87 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of March 31, 2016, ComEd's net credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information.

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PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's

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

lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of March 31, 2016, PECO had no net credit exposure to suppliers.

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

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of March 31, 2016, PECO had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of March 31, 2016, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At March 31, 2016, BGE had credit exposure of \$2 million related to off-system sales which is mitigated by parental guarantees, letters of credit or right to offset clauses within other contracts with those third-party suppliers.

Pepco's, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents Pepco's, DPL's and ACE's net credit exposure. As of March 31, 2016, Pepco's, DPL's and ACE's net credit exposures to suppliers were immaterial.

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

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco's, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 6 Regulatory Matters of the PHI 2015 Form 10-K for additional information.

DPL's natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of March 31, 2016, DPL had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

***Collateral and Contingent-Related Features (All Registrants)***

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

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

<b>Credit-Risk Related Contingent Feature</b>	<b>March 31, 2016</b>	<b>December 31, 2015</b>
Gross Fair Value of Derivative Contracts Containing this Feature <sup>(a)</sup>	\$ (979)	\$ (932)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements <sup>(b)</sup>	728	684
<b>Net Fair Value of Derivative Contracts Containing This Feature<sup>(c)</sup></b>	<b>\$ (251)</b>	<b>\$ (248)</b>

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

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

- (b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
- (c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of \$1,063 million and letters of credit posted of \$519 million and cash collateral held of \$16 million and letters of credit held of \$96 million as of March 31, 2016 for external counterparties with derivative positions. Generation had cash collateral posted of \$1,267 million and letters of credit posted of \$497 million and cash collateral held of \$21 million and letters of credit held of \$78 million at December 31, 2015 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e. to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of \$1.9 billion and \$2.0 billion as of March 31, 2016 and December 31, 2015, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of March 31, 2016, Generation and Exelon's swaps were in an asset position, with a fair value of \$1 million and \$40 million, respectively.

See Note 25 Segment Information of the Exelon 2015 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of March 31, 2016, ComEd held no collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of March 31, 2016, ComEd held approximately \$19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. If ComEd lost its investment grade credit rating as of March 31, 2016, it would have been required to post approximately \$17 million of collateral to its counterparties. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2016, PECO was not required to post collateral for any of these



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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

agreements. If PECO lost its investment grade credit rating as of March 31, 2016, PECO could have been required to post approximately \$22 million of collateral to its counterparties.

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

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

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2016, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of March 31, 2016, BGE could have been required to post approximately \$28 million of collateral to its counterparties.

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

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

DPL's natural gas derivative contracts contain provisions that could require DPL to post collateral in an amount equal to the unsecured credit threshold if exceeded when the aggregate fair value of the transactions is in a net loss position. The obligations of DPL are standalone obligations without the guaranty of PHI. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder.

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

**10. Debt and Credit Agreements (All Registrants)**

***Short-Term Borrowings***

Exelon, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI meets its short-term liquidity requirement primarily through the issuance of commercial paper, short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Commercial Paper**

The Registrants had the following amounts of commercial paper borrowings outstanding as of March 31, 2016 and December 31, 2015:

<b>Commercial Paper Borrowings</b>	<b>March 31, 2016</b>	<b>December 31, 2015</b>
Generation	\$ 1,378	\$
ComEd	643	294
BGE	150	210
PHI Corporate	442	484
Pepco		64
DPL	75	105
ACE		5

**Short-Term Loan Agreements**

On July 30, 2015, PHI entered into a \$300 million term loan agreement. The net proceeds of the loan were used to repay PHI's outstanding commercial paper and for general corporate purposes. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.95%, and all indebtedness thereunder is unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement, must be repaid in full on or before July 28, 2016. On April 4, 2016, PHI repaid \$300 million of its term loan in full.

On January 13, 2016, PHI entered into a \$500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper, and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured, and the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the Loan Agreement, must be repaid in full on or before March 27, 2017. The loan agreement is reflected in Exelon's and PHI's Consolidated Balance Sheets within Short-term borrowings.

On February 22, 2016, Generation and EDF entered into separate member revolving promissory notes with CENG to finance short-term working capital needs. The notes are scheduled to mature on January 31, 2017 and bear interest at a variable rate equal to LIBOR plus 1.75%. As of March 31, 2016, \$25 million was outstanding under each note. The \$25 million note outstanding between Generation and CENG is eliminated in consolidation and therefore not reflected in Exelon's or Generation's Consolidated Balance Sheets. The \$25 million note with EDF is reflected in Exelon's and Generation's Consolidated Balance Sheet within Short-term borrowings.

**Credit Agreements**

On January 5, 2016, Generation entered into a credit agreement establishing a \$150 million bilateral credit facility, scheduled to mature in January of 2019. This facility will solely be utilized by Generation to issue lines of credit. This facility does not back Generation's commercial paper program.

On April 1, 2016, the credit agreement for CENG's \$100 million bilateral credit facility was amended to increase the overall facility size to \$200 million. This facility is utilized by CENG to fund working capital and capital projects. The facility does not back Generation's commercial paper program.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Variable Rate Demand Bonds**

As of March 31, 2016 and December 31, 2015, \$105 million in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year on Exelon's, PHI's and DPL's Consolidated Balance Sheet. See Note 10 Debt of the PHI 2015 Form 10-K for additional information.

**Long-Term Debt****Issuance of Long-Term Debt**

During the three months ended March 31, 2016, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	\$ 32	Albany Green Energy biomass generation development
Generation	Renewable Power Generation Nonrecourse Debt	4.11%	March 31, 2035	\$ 150	Paydown long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general corporate purposes.

On April 7, 2016, Exelon issued and sold \$1.8 billion in aggregate principal amount of notes consisting of \$300 million of 2.45% Notes due 2021, \$750 million of 3.40% Notes due 2026 and \$750 million of 4.45% Notes due 2046. A portion of the proceeds of the notes will be used to repay commercial paper issued by PHI and for general corporate purposes, which may include the repayment of outstanding indebtedness.

**Retirement and Redemptions of Long-Term Debt**

During the three months ended March 31, 2016, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	AVSR DOE Nonrecourse Debt	2.29 - 3.56%	January 5, 2037	\$ 5
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	\$ 15
Generation	CEU Upstream Nonrecourse Debt	LIBOR + 2.75%	January 14, 2019	\$ 7
Generation	ExGen Texas Power Nonrecourse Debt	5.00%	September 18, 2021	\$ 2
Generation	Sacramento PV Energy Nonrecourse Debt	2.58%	December 31, 2030	\$ 33
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	\$ 32
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	\$ 1
ACE	ACE Funding Transition Bonds	5.55%	October 20, 2023	\$ 8
ACE	ACE Funding Transition Bonds	5.05%	October 20, 2020	\$ 3

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On April 1, 2016, BGE paid down \$1 million of principal of its 5.72% Rate Stabilization Bonds due 2016 and \$38 million of principal of its 5.82% Rate Stabilization Bonds due 2017.

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

On April 5, 2016, Generation paid down \$1 million of principal of its 2.29% - 3.56% AVSR DOE Nonrecourse debt.

On April 15, 2016, Generation paid down \$10 million of principal of its 5.25% ExGen Renewables I Nonrecourse debt.

On April 20, 2016, ACE paid down \$8 million of principal of its 5.55% ACE Funding Transition Bonds and \$3 million of principal of its 5.05% ACE Funding Transition Bonds.

***CEU Upstream Nonrecourse Debt***

In July 2011, CEU Holdings, LLC, a wholly owned subsidiary of Generation, entered into a 5-year reserve based lending agreement (RBL) associated with certain Upstream oil and gas properties that it owns. The lenders do not have recourse against Exelon or Generation in the event of default pursuant to the RBL. Borrowings under this arrangement are secured by the assets and equity of CEU Holdings. The commitment level can be decreased if the assets no longer support the current borrowing base, which may result in repayment of a portion or all of the outstanding balance, or potential foreclosure of the assets. The commitment can be increased up to \$500 million if the assets support a higher borrowing base and CEU Holdings is able to obtain additional commitments from lenders. Calculations of the borrowing base are impacted by projected production and commodity prices. The facility was amended and extended on January 14, 2014 through January 2019. As of December 31, 2015, \$68 million was outstanding under the facility with interest payable monthly at a variable rate equal to LIBOR plus 2.50% and the borrowing base committed under the facility was \$85 million.

In February 2016, as part of their semi-annual borrowing base re-determination testing, the RBL lenders notified CEU Holdings that the RBL borrowing base was decreased to \$45 million, resulting in a borrowing base deficiency under the RBL of \$23 million. Given the decline in value of the Upstream assets resulting from lower commodity prices, CEU Holdings chose not to provide the lenders with a formal plan for curing the borrowing base deficiency by March 31, 2016, as was required by the RBL. The lenders have sent CEU Holdings a notice of event of default and demand for cure. CEU Holdings is currently in discussions with the lenders regarding the resolution of the matter. The resolution could include negotiating a forbearance agreement that would provide for the potential sale of Upstream assets in order to wind down the Upstream business of CEU Holdings. Consistent with these discussions, the RBL lenders have not yet accelerated the debt outstanding under the RBL. However, on March 31, 2016, \$7 million of the debt was repaid using CEU Holdings' cash, resulting in an outstanding debt balance of \$61 million with interest payable monthly at a variable rate equal to LIBOR plus 2.75% and a borrowing base deficiency under the RBL of \$16 million. The outstanding debt balance of \$61 million was classified within Long-term debt due within one year on Exelon's and Generation's Consolidated Balance Sheets. The ultimate resolution of this matter has no direct effect on any Exelon or Generation credit facilities or other debt of an Exelon entity. See Note 14 Debt and Credit Agreements of the Exelon 2015 Form 10-K and Note 6 Impairment of Long-Lived Assets for additional information.

***Other Financing Activities******Accounts Receivable Agreement***

In February 2016, PES entered into an accounts receivable sales agreement with a financing institution in which PES will borrow approximately \$41 million to complete the construction of an energy efficiency project that is expected to be completed in 2018. Pursuant to the assignment of PES' rights to the customer receivables to the financing institution, upon customer acceptance of the energy efficiency project, the customer will pay the financing institution over a 16 year period. At March 31, 2016, PES has borrowed \$3 million under the contract which is classified as Long-term debt due within one year on Exelon's and Generation's Consolidated Balance Sheet.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**11. Income Taxes (All Registrants)**

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

	Three Months Ended March 31, 2016								Successor	Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Peppo <sup>(a)</sup>	DPL <sup>(a)</sup>	ACE <sup>(a)</sup>	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:										
State income taxes, net of										
Federal income tax benefit (b)	(1.1)	3.7	5.1	1.0	5.2	(2.5)	(2.7)	5.9	5.4	11.9
Qualified nuclear										
decommissioning trust fund										
income	5.6	4.2								
Domestic production activities										
deduction										
Health care reform legislation										
Amortization of investment tax										
credit, including deferred taxes										
on basis difference	(1.6)	(1.0)	(0.3)	(0.1)	(0.1)		0.1	0.2		(0.9)
Plant basis differences	(5.5)		(0.1)	(9.3)	(0.6)	2.8	0.7	0.6		(13.5)
Production tax credits and other										
credits	(5.1)	(3.9)								
Non-controlling interest	0.5	0.3								
Merger expenses	33.6					(16.5)	(22.1)	(17.0)	(15.1)	11.1
Other	(2.0)	(1.6)	0.4	(0.9)			0.1	0.1	0.2	3.6
Effective income tax rate	59.4%	36.7%	40.1%	25.7%	39.5%	18.8%	11.1%	24.8%	25.5%	47.2%

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Three Months Ended March 31, 2015									
	<i>Predecessor</i>									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:										
State income taxes, net of Federal income tax benefit	2.6	2.7	5.0	1.2	5.3	7.2	5.3	5.7	5.9	
Qualified nuclear decommissioning trust fund income	1.9	3.0								
Domestic production activities deduction	(2.2)	(3.4)								
Health care reform legislation					0.2					
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(1.4)	(0.3)	(0.1)		(0.5)	(0.1)	(0.2)	(1.4)	
Plant basis differences	(1.3)		(0.3)	(6.7)	(0.3)	(4.9)	(8.5)	(0.9)	(2.8)	
Production tax credits and other credits	(1.8)	(2.8)								
Non-controlling interest	(0.7)	(1.1)								
Other	0.4	(0.2)	0.2		0.2	(0.7)	(0.1)		(1.0)	
Effective income tax rate	33.0%	31.8%	39.6%	29.4%	40.4%	36.1%	31.6%	39.6%	35.7%	

(a) Pepco, DPL and ACE recognized a loss before income taxes for the three months ended March 31, 2016, and PHI recognized a loss before income taxes for the period of March 24, 2016, through March 31, 2016. As a result, positive percentages represent an income tax benefit for the periods presented.

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

**Accounting for Uncertainty in Income Taxes**

The Registrants have the following unrecognized tax benefits as of March 31, 2016 and December 31, 2015:

	<i>Successor</i>									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
March 31, 2016	\$ 950	\$ 531	\$ (12)	\$	\$ 120	\$ 168	\$ 86	\$ 39	\$ 24	

	<i>Predecessor</i>									
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE	
December 31, 2015	\$ 1,101	\$ 534	\$ 142	\$	\$ 120	\$ 22	\$ 8	\$ 3	\$	

Exelon and ComEd's unrecognized tax benefits changed by \$328 million and \$154 million, respectively, as of March 31, 2016 as a result of the lease termination on the like-kind exchange position discussed below. In addition, as a result of the merger, an assessment and remeasurement of certain federal and state uncertain income tax positions resulted in an increase in unrecognized tax benefits at Exelon, PHI, Pepco, DPL and ACE of \$177 million, \$146 million, \$78 million, \$36 million and \$24 million, respectively.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

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

*Like-Kind Exchange*

As of March 31, 2016, Exelon and ComEd have approximately \$75 million and \$(12) million of unrecognized state income tax benefits that could significantly decrease and increase, respectively, within the 12 months after the reporting date as a result of a decision or settlement in the like-kind exchange litigation described below. These unrecognized tax benefits, if recognized, would decrease Exelon's effective tax rate by \$75 million and increase ComEd's effective tax rate by \$12 million.

*Settlement of Income Tax Audits and Litigation*

As of March 31, 2016, Exelon, Generation, BGE, Pepco, and DPL have approximately \$270 million, \$67 million, \$120 million, \$63 million, and \$20 million of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits and potential settlements. Of the above unrecognized tax benefits, Exelon and Generation have \$67 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, Pepco, and DPL, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

**Other Income Tax Matters**

*Like-Kind Exchange (Exelon and ComEd)*

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately \$1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately \$1.2 billion was taxable in 1999.

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

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is likely. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.



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

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately \$265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately \$172 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a \$172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court and the trial took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. While the Tax Court could reach its decision as early as 2016, the litigation could take three to five years if an appeal is necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, as of March 31, 2016, potential tax of \$460 million and after-tax interest of \$300 million, exclusive of penalties, could become payable (net of a \$65 million deposit made to the IRS in 2015). Of the above amounts, approximately \$275 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. Interest will continue to accrue until such time as payment is made. An appeal of an adverse decision in the Tax Court would necessitate either the posting of a bond or the payment of the tax and interest for the tax years before the court.

In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of \$335 million. On March 31, 2016, Exelon entered into an agreement to terminate its interests in the remaining two municipal-owned electric generation properties in exchange for \$360 million. As a result of the lease terminations, any remaining tax gain related to the LKE position taken in 1999 will no longer be deferred. In the event of a successful outcome in the litigation, Exelon will not be required to pay the after-tax interest described in the preceding paragraph (\$300 million as of March 31, 2016) but will be required to report the remaining \$460 million of tax due on the transaction in Exelon's 2014 and 2016 tax years. Of that approximately \$230 million is attributable to ComEd. The tax liabilities from the terminations will not result in a current year cash outflow due to the utilization of net operating losses and tax credit carryforwards.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Long-Term State Tax Apportionment (Exelon, Generation and PHI)**

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon and Generation to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes, such as the merger with PHI. As a result of the merger, Exelon and Generation reevaluated their long-term state tax apportionment for all states where they have state income tax obligations, which include Delaware, Illinois, Maryland, New Jersey, Pennsylvania, and Washington D.C., as well as other states. The total effect of revising the long-term state tax apportionment resulted in the recording of deferred state tax benefit in the amount of \$1 million and a state tax expense of \$6 million, net of tax, for Exelon and Generation, respectively. Further, Exelon and PHI recorded deferred state tax liabilities of \$59 million and \$8 million, net of tax, respectively, as part of purchase accounting during the first quarter of 2016.

**12. Nuclear Decommissioning (Exelon and Generation)*****Nuclear Decommissioning Asset Retirement Obligations***

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2015 to March 31, 2016:

Nuclear decommissioning ARO at December 31, 2015 <sup>(a)</sup>	\$ 8,246
Accretion expense	106
Net increase due to changes in, and timing of, estimated cash flows	60
Nuclear decommissioning ARO at March 31, 2016 <sup>(a)</sup>	\$ 8,412

(a) Includes \$6 million and \$7 million as the current portion of the ARO at March 31, 2016 and December 31, 2015 which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During the three months ended March 31, 2016, Generation's ARO increased by approximately \$60 million primarily driven by a number of individually small items, which were included within the estimated costs to decommission the Oyster Creek nuclear unit as a result of the completion of an updated decommissioning cost study received during the first quarter.

The financial statement impact related to the increase in the ARO due to the changes in, and timing of, estimated cash flows resulted in a corresponding increase in Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. This increase in cost will be amortized over the remaining useful life of the Oyster Creek nuclear unit, which is set to retire by the end of 2019.

***Nuclear Decommissioning Trust Fund Investments***

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At March 31, 2016 and December 31, 2015, Exelon and Generation had NDT fund investments totaling \$10,526 million and \$10,342 million, respectively.

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

The following table provides unrealized gains on NDT funds for the three months ended March 31, 2016 and 2015:

		<b>Exelon and Generation</b>	
		<b>Three Months Ended March 31,</b>	
		<b>2016</b>	<b>2015</b>
Net unrealized gains on decommissioning trust funds	Regulatory Agreement Units <sup>(a)</sup>	\$ 79	\$ 48
Net unrealized gains on decommissioning trust funds	Non-Regulatory Agreement Units <sup>(b)(c)</sup>	52	40

- (a) Net unrealized gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
- (b) Excludes \$2 million and \$10 million of net unrealized gain related to the Zion Station pledged assets for the three months ended March 31, 2016 and 2015, respectively. Net unrealized gains related to Zion Station pledged assets are included in the Payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
- (c) Net unrealized gains related to Generation's NDT funds with Non-Regulatory Agreement Units are included within Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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

Refer to Note 3 Regulatory Matters and Note 26 Related Party Transactions of the Exelon 2015 Form 10-K for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

***Zion Station Decommissioning***

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, under which ZionSolutions has assumed responsibility for completing certain decommissioning activities at Zion Station, which is located in Zion, Illinois and ceased operation in 1998. See Note 16 Asset Retirement Obligations of the Exelon 2015 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to Pledged assets for Zion Station decommissioning within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation's and Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, are recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal,

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

and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately \$85 million which is included within the nuclear decommissioning ARO at March 31, 2016. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at March 31, 2016 and December 31, 2015:

	<b>Exelon and Generation</b>	
	<b>March 31, 2016</b>	<b>December 31, 2015</b>
Carrying value of Zion Station pledged assets	\$ 183	\$ 206
Payable to Zion Solutions <sup>(a)</sup>	166	189
Current portion of payable to Zion Solutions <sup>(b)</sup>	95	99
Cumulative withdrawals by Zion Solutions to pay decommissioning costs <sup>(c)</sup>	812	786

(a) Excludes a liability recorded within Exelon's and Generation's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.

(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.

(c) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT fund earnings.

***NRC Minimum Funding Requirements***

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

Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2015. This report reflects the status of decommissioning funding assurance as of December 31, 2014. Due to increased cost estimates received in the second half of 2014, Braidwood Unit 1, Braidwood Unit 2, and Byron Unit 2 did not meet the NRC's minimum funding assurance criteria as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. During this period, Generation will monitor funding assurance and new developments, including the impact of a 20-year license renewal for Braidwood and Byron, to assess the status of funding assurance and to take steps, if necessary, to address any funding shortfall on these funds on or before March 31, 2017. On February 4, 2016, Generation submitted to the NRC an updated decommissioning funding status report for Braidwood Units 1 and 2, and Byron Unit 2. This updated report reflected the recently approved license renewals for these units, and showed that the shortfall identified in the March 31, 2015 report has now been resolved and that Generation has provided adequate decommissioning funding assurance for each unit.

On March 31, 2016, Generation submitted its NRC required annual decommissioning funding status report as of December 31, 2015 for reactors that have been shut down or are within five years of shut down except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above). As of December 31, 2015, Generation provided adequate decommissioning funding assurance for all of its reactors that have been shut down or are within five years of shut down except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. As discussed in Note 16 Asset Retirement Obligations of Exelon's 2015 Form 10-K, the amount collected from PECO ratepayers will be adjusted in the next filing to the PaPUC with new rates effective January 1, 2018.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****13. Retirement Benefits (All Registrants)**

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

Effective March 23, 2016, Exelon became the sponsor of all PHI's defined benefit pension and other postretirement benefit plans, and assumed PHI's benefit plan obligations and related assets. As a result, PHI's benefit plan net obligation and related regulatory assets were transferred to Exelon. The legacy PHI pension and other postretirement benefit plans were remeasured on February 29, 2016, as a result of the short time between the merger close and the end of the first quarter of 2016, using current assumptions, including the discount rate. The valuation is considered preliminary and Exelon may update these amounts in future quarters to reflect assumptions at March 23, 2016.

***Defined Benefit Pension and Other Postretirement Benefits***

During the first quarter of 2016, Exelon received an updated valuation of its legacy pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2016. This valuation resulted in an increase to the pension obligation of \$35 million and a decrease to the other postretirement benefit obligation of \$8 million. Additionally, accumulated other comprehensive loss increased by approximately \$2 million (after tax), regulatory assets increased by approximately \$27 million, and regulatory liabilities increased by approximately \$3 million.

The majority of the 2016 pension benefit cost for legacy Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 4.29%. The majority of the 2016 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.71% for funded plans and a discount rate of 4.29%.

The 2016 pension benefit costs for the legacy PHI plans are calculated using an expected long-term rate of return on plan assets of 6.50% and a discount rate of 4.18% for the majority of the pension plans. The 2016 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.75% and a discount rate of 4.00%.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to capitalization, for the three months ended March 31, 2016 and 2015.

	<b>Pension Benefits</b>		<b>Other Postretirement Benefits</b>	
	<b>Three Months Ended</b>		<b>Three Months Ended</b>	
	<b>March 31,</b>		<b>March 31,</b>	
	<b>2016<sup>(a)</sup></b>	<b>2015</b>	<b>2016<sup>(a)</sup></b>	<b>2015</b>
<b>Components of net periodic benefit cost:</b>				
Service cost	\$ 78	\$ 82	\$ 26	\$ 30
Interest cost	190	178	43	42
Expected return on assets	(263)	(257)	(38)	(38)
Amortization of:				
Prior service cost (benefit)	3	3	(44)	(43)
Actuarial loss	127	143	14	20
<b>Net periodic benefit cost</b>	<b>\$ 135</b>	<b>\$ 149</b>	<b>\$ 1</b>	<b>\$ 11</b>

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





**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	<i>Predecessor</i>			
	<b>PHI</b>			
	<b>Pension Benefits</b>		<b>Other Postretirement Benefits</b>	
	<b>January 1, 2016 to March 23, 2016</b>	<b>Three Months Ended March 31, 2015</b>	<b>January 1, 2016 to March 23, 2016</b>	<b>Three Months Ended March 31, 2015</b>
<b>Components of net periodic benefit cost:</b>				
Service cost	\$ 12	\$ 14	\$ 1	\$ 2
Interest cost	26	27	6	6
Expected return on assets	(30)	(35)	(5)	(6)
Amortization of:				
Prior service cost (benefit)			(3)	(3)
Actuarial loss	14	16	2	3
<b>Net periodic benefit cost</b>	<b>\$ 22</b>	<b>\$ 22</b>	<b>\$ 1</b>	<b>\$ 2</b>

The amounts below represent Generation, ComEd, PECO, BGE, PHI, Pepco, DPL, ACE, BSC and PHISCO's allocated portion of the pension and postretirement benefit plan costs, which were included in Property, plant and equipment within the respective Consolidated Balance Sheets and Operating and maintenance expense within the Consolidated Statement of Operations and Comprehensive Income during the three months ended March 31, 2016 and 2015.

<b>Pension and Other Postretirement Benefit Costs</b>	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
Exelon	\$ 136	\$ 160
Generation	54	67
ComEd	41	52
PECO	8	10
BGE	16	17
BSC <sup>(a)</sup>	14	14
Pepco <sup>(b)</sup>	8	8
DPL <sup>(b)</sup>	5	4
ACE <sup>(b)</sup>	4	4
PHISCO <sup>(a)(b)</sup>	9	8

	<i>Successor</i>		<i>Predecessor</i>	
	<b>March 24, 2016 to</b>		<b>January 1, 2016 to</b>	
	<b>March 31, 2016</b>	<b>March 23, 2016</b>	<b>Three Months Ended March 31, 2015</b>	<b>Three Months Ended March 31, 2015</b>
<b>Pension and Other Postretirement Benefit Costs</b>				
PHI	\$ 3	\$ 23	\$ 24	

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

(b)

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Pepco, DPL, ACE and PHISCO's pension and postretirement benefit costs for the three months ended March 31, 2016 include \$7 million, \$4 million, \$3 million and \$9 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016. PHI, Pepco, DPL, ACE and PHISCO's predecessor pension and other postretirement benefit costs for the three months ended March 31, 2015 were \$24 million, \$8 million, \$4 million, \$4 million and \$8 million, respectively. These amounts are not included in Exelon's net periodic benefit cost for the three months ended March 31, 2015 shown in the components of net periodic cost table of the Defined Benefit Pension and Other Postretirement Benefits section above.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Defined Contribution Savings Plans**

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three months ended March 31, 2016 and 2015:

Savings Plan Matching Contributions	Three Months Ended March 31,	
	2016	2015
Exelon	\$ 26	\$ 22
Generation	12	13
ComEd	6	5
PECO	2	1
BGE	1	2
BSC <sup>(a)</sup>	5	1
Pepco <sup>(b)</sup>	1	1
DPL <sup>(b)</sup>	1	
PHISCO <sup>(a)(b)</sup>	1	2

Savings Plan Matching Contributions	Successor	Predecessor
	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016
	Three Months Ended March 31, 2016	Three Months Ended March 31, 2015
PHI	\$ 3	\$ 3

- (a) These amounts primarily represent amounts billed to Exelon and PHI's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO, BGE, Pepco and DPL amounts above.
- (b) Pepco's, DPL's and PHISCO's matching contributions for the three months ended March 31, 2016 include \$1 million, \$1 million and \$1 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016, which is not included in Exelon's matching contributions for the three months ended March 31, 2016.

**14. Severance (All Registrants)**

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

**Ongoing Severance Plans**

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

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Exelon and Generation recorded \$2 million and \$20 million of severance costs associated with these ongoing severance benefits for the three months ended March 31, 2016 and 2015, respectively, within Operating

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

and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income. For Generation, the amount includes \$1 million for amounts billed by BSC through intercompany allocations for the three months ended March 31, 2016.

**Cost Management Program-Related Severance**

In August 2015, Exelon announced a cost management program focused on cost savings at BSC and Generation, including the elimination of approximately 500 positions. These actions are in response to the continuing economic challenges confronting all parts of Exelon's business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity. Exelon expects that approximately 250 corporate support positions in BSC and approximately 250 positions located throughout Generation will be eliminated.

Upon Senior Management approval of the cost management targets and initiatives in the first quarter of 2016, Exelon recorded severance benefit costs of \$17 million associated with the anticipated position reductions. The final amount of the charge will ultimately depend on the specific employees severed.

For the three months ended March 31, 2016, the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
Severance benefits <sup>(a)</sup>	\$ 17	\$ 12	\$ 3	\$ 1	\$ 1

(a) The amounts above for Generation, ComEd, PECO and BGE include \$7 million, \$3 million, \$1 million, and \$1 million, respectively, for amounts billed by BSC through intercompany allocations for the three months ended March 31, 2016.

**Severance Costs Related to the PHI Merger**

Upon closing the PHI Merger, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration.

For the three months ended March 31, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<i>Successor</i> <b>PHI</b>	<b>Pepco</b>	<b>DPL</b>	<b>ACE</b>
Severance benefits <sup>(a)</sup>	\$ 52	\$ 10	\$ 2	\$ 1	\$ 1	\$ 37	\$ 18	\$ 11	\$ 8

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE include \$9 million, \$2 million, \$1 million, \$1 million, \$18 million, \$11 million and \$8 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations for the three months ended March 31, 2016.

Cash payments under the plan begin in May 2016 and will continue through 2020.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Severance Liability**

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

<b>Severance Liability</b>	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>	<i>Successor</i> <b>PHI</b>	<b>Pepco</b>	<b>DPL</b>	<b>ACE</b>
Balance at December 31, 2015	\$ 35	\$ 23	\$ 3	\$	\$ 1	\$	\$	\$	\$
Severance charges <sup>(a)(b)</sup>	71	7				51			
Payments	(4)	(3)							
Balance at March 31, 2016	\$ 102	\$ 27	\$ 3	\$	\$ 1	\$ 51	\$	\$	\$

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for the PHI post-merger integration and the cost management program.

(b) Represents activity from March 24, 2016 to March 31, 2016 for PHI, Pepco, DPL and ACE.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**15. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, PECO and PHI)**

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the three months ended March 31, 2016 and 2015:

Three Months Ended March 31, 2016	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
<b>Exelon<sup>(a)</sup></b>						
Beginning balance	\$ (19)	\$ 3	\$ (2,565)	\$ (40)	\$ (3)	\$ (2,624)
OCI before reclassifications	(10)	(1)	67	6	(3)	59
Amounts reclassified from AOCI <sup>(b)</sup>	3		(34)			(31)
Net current-period OCI	(7)	(1)	33	6	(3)	28
Ending balance	\$ (26)	\$ 2	\$ (2,532)	\$ (34)	\$ (6)	\$ (2,596)
<b>Generation<sup>(a)</sup></b>						
Beginning balance	\$ (21)	\$ 1	\$	\$ (40)	\$ (3)	\$ (63)
OCI before reclassifications	(8)			6	(2)	(4)
Amounts reclassified from AOCI <sup>(b)</sup>	3					3
Net current-period OCI	(5)			6	(2)	(1)
Ending balance	\$ (26)	\$ 1	\$	\$ (34)	\$ (5)	\$ (64)
<b>PECO<sup>(a)</sup></b>						
Beginning balance	\$	\$ 1	\$	\$	\$	\$ 1
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>						
Net current-period OCI						
Ending balance	\$	\$ 1	\$	\$	\$	\$ 1
<b>PHI Predecessor<sup>(a)</sup></b>						
Beginning balance January 1, 2016	\$ (8)	\$	\$ (28)	\$	\$	\$ (36)



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OCI before reclassifications						2			2
Amounts reclassified from AOCI <sup>(b)</sup>						(1)			(1)
Net current-period OCI						1			1
Ending balance March 23, 2016 <sup>(c)</sup>	\$	(8)	\$	\$	(27)	\$	\$	\$	(35)

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Three Months Ended March 31, 2015	Gains and (Losses) on Hedging Activity	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
<b>Exelon<sup>(a)</sup></b>						
Beginning balance	\$ (28)	\$ 3	\$ (2,640)	\$ (19)	\$	\$ (2,684)
OCI before reclassifications	(11)		(26)	(12)		(49)
Amounts reclassified from AOCI <sup>(b)</sup>	17		43			60
Net current-period OCI	6		17	(12)		11
Ending balance	\$ (22)	\$ 3	\$ (2,623)	\$ (31)	\$	\$ (2,673)
<b>Generation<sup>(a)</sup></b>						
Beginning balance	\$ (18)	\$ 1	\$	\$ (19)	\$	\$ (36)
OCI before reclassifications	(6)			(12)		(18)
Amounts reclassified from AOCI <sup>(b)</sup>	1					1
Net current-period OCI	(5)			(12)		(17)
Ending balance	\$ (23)	\$ 1	\$	\$ (31)	\$	\$ (53)
<b>PECO<sup>(a)</sup></b>						
Beginning balance	\$	\$ 1	\$	\$	\$	\$ 1
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>						
Net current-period OCI						
Ending balance	\$	\$ 1	\$	\$	\$	\$ 1
<b>PHI Predecessor<sup>(a)</sup></b>						
Beginning balance	\$ (9)	\$	\$ (37)	\$	\$	\$ (46)
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>			1			1
Net current-period OCI			1			1
Ending balance	\$ (9)	\$	\$ (36)	\$	\$	\$ (45)

- (a) All amounts are net of tax. Amounts in parenthesis represent a decrease in AOCI.
- (b) See next tables for details about these reclassifications.
- (c) As a result of the PHI Merger, the PHI predecessor balances at March 23, 2016 were reduced to zero on March 24, 2016 due to purchase accounting adjustments applied to PHI.

ComEd, PECO, BGE, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the three months ended March 31, 2016 and 2015. The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the three months ended March 31, 2016 and 2015.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Three Months Ended March 31, 2016**

Details about AOCI components	Items reclassified out of AOCI <sup>(a)</sup>			Affected line item in the Statement of Operations and Comprehensive Income
	Three Months Ended March 31, 2016 Exelon	Three Months Ended March 31, 2016 Generation	Predecessor January 1, 2016 to March 23, 2016 PHI	
<b>Gains and (losses) on cash flow hedges</b>				
Other cash flow hedges	\$ (5)	\$ (5)	\$	Interest expense
Total before tax	(5)	(5)		
Tax expense	2	2		
Net of tax	\$ (3)	\$ (3)	\$	Comprehensive income
<b>Amortization of pension and other postretirement benefit plan items</b>				
Prior service costs <sup>(b)</sup>	\$ (20)	\$	\$	
Actuarial losses <sup>(b)</sup>	76		1	
Total before tax	56		1	
Tax benefit	(22)			
Net of tax	\$ 34	\$	\$ 1	
<b>Total Reclassifications</b>	<b>\$ 31</b>	<b>\$ (3)</b>	<b>\$ 1</b>	<b>Comprehensive income</b>

**Three Months Ended March 31, 2015**

Details about AOCI components	Items reclassified out of AOCI <sup>(a)</sup>			Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	Predecessor PHI	
<b>Gains and (losses) on cash flow hedges</b>				
Terminated interest rate swaps	\$ (26)	\$	\$	Other, net
Energy related hedges	2	2		Operating revenues
Other cash flow hedges	(3)	(3)		Interest expense
Total before tax	(27)	(1)		
Tax benefit	10			

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Net of tax	\$ (17)	\$ (1)	\$	Comprehensive income
<b>Amortization of pension and other postretirement benefit plan items</b>				
Prior service costs <sup>(b)</sup>	\$ 19	\$	\$	
Actuarial losses <sup>(b)</sup>	(90)			(2)
Total before tax	(71)			(2)
Tax benefit	28			1
Net of tax	\$ (43)	\$	\$ (1)	
<b>Total Reclassifications</b>	<b>\$ (60)</b>	<b>\$ (1)</b>	<b>\$ (1)</b>	<b>Comprehensive income</b>

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

(a) Amounts in parenthesis represent a decrease in net income.

(b) This AOCI component is included in the computation of net periodic pension and OPEB cost (see Note 13 Retirement Benefits for additional details).

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,	
	2016	2015
<b>Exelon</b>		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	\$ 7	\$ 8
Actuarial loss reclassified to periodic cost	(30)	(35)
Pension and non-pension postretirement benefit plans valuation adjustment		17
Change in unrealized gain/(loss) on cash flow hedges	3	(2)
Change in unrealized loss on equity investments	2	
Change in unrealized gain on marketable securities	1	
<b>Total</b>	<b>\$ (17)</b>	<b>\$ (12)</b>
<b>Generation</b>		
Change in unrealized gain on cash flow hedges	\$ 2	\$ 5
Change in unrealized loss on equity investments	2	
<b>Total</b>	<b>\$ 4</b>	<b>\$ 5</b>

	<i>Predecessor</i>	
	January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015
<b>PHI</b>		
Pension and non-pension postretirement benefit plans:		
Actuarial loss reclassified to periodic cost	\$	\$ (1)

**16. Mezzanine Equity (Exelon, Generation and PHI)****Contingently Redeemable Noncontrolling Interest (Exelon and Generation)**

In November 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to sell a portion of its equity to a tax equity investor. Pursuant to the operating agreement, in certain circumstances the equity contributed by the noncontrolling interest holder could be contingently redeemable. These circumstances are outside of the control of Generation and the noncontrolling interest holder resulting in a portion of the noncontrolling interest being considered contingently redeemable and thus presented in mezzanine equity on the consolidated balance sheet.

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The following table summarizes the changes in the contingently redeemable noncontrolling interest for the three months ended March 31, 2016:

Balance at December 31, 2015	\$ 28
Cash received from noncontrolling interest	10
Release of contingency	(19)
Balance at March 31, 2016	\$ 19

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Preferred Stock (PHI)**

In connection with the PHI Merger Agreement, Exelon purchased 18,000 originally issued shares of PHI preferred stock for a purchase price of \$180 million. PHI excluded the preferred stock from equity at December 31, 2015 since the preferred stock contained conditions for redemption that were not solely within the control of PHI. Management determined that 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. As of December 31, 2015, the fair value of the derivative related to the preferred stock was estimated to be \$18 million based on PHI's updated assessment and was included in current assets with a corresponding increase in preferred stock on the Consolidated Balance Sheet. Immediately prior to the merger date, PHI updated its assessment of the fair value of the derivative and reduced the fair value to zero, recording the \$18 million decrease in fair value as a reduction of Other, net in the predecessor period January 1, 2016 to March 23, 2016.

On March 23, 2016, the preferred stock was cancelled and the \$180 million cash consideration previously received by PHI to issue the preferred stock was treated as additional merger purchase price consideration.

**17. Earnings Per Share (Exelon)**

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Three Months Ended March 31,	
	2016	2015
<b>Exelon</b>		
Net income attributable to common shareholders	\$ 173	\$ 693
Weighted average common shares outstanding - basic	923	862
Assumed exercise and/or distributions of stock-based awards	2	5
Weighted average common shares outstanding - diluted	925	867

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 13 million and 15 million for the three months ended March 31, 2016 and 2015, respectively. The number of equity units related to the PHI Merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was 4 million for the three months ended March 31, 2016 and less than 1 million for the three months ended March 31, 2015. Refer to Note 19 - Shareholder's Equity of the Exelon 2015 Form 10-K for further information regarding the equity units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of \$2.3 billion as of March 31, 2016. In 2008, Exelon management decided to defer indefinitely any share repurchases.





**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****18. Commitments and Contingencies (All Registrants)**

The following is an update to the current status of commitments and contingencies set forth in Note 23 of the Exelon 2015 Form 10-K and Note 16 of the PHI 2015 Form 10-K. See Note 4 Mergers, Acquisitions and Dispositions for further discussion on the PHI Merger commitments.

**Commitments*****Constellation Merger Commitments (Exelon and Generation)***

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately \$1 billion. The direct investment estimate includes \$95 million to \$120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses.

The direct investment commitment also includes \$500 million to \$600 million relating to Exelon and Generation's development or assistance in the development of 275-300 MWs of new generation in Maryland, which is expected to be completed over a period of 10 years. As of March 31, 2016, Exelon and Generation have incurred \$398 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date. The MDPSC Order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax \$44 million loss contingency related to this generation development commitment. While this \$44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately \$105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant.

***Equity Investment Commitments (Exelon and Generation)***

Generation has entered into equity purchase agreements that include commitments to invest additional equity through incremental payments to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately \$20 million of in-kind services and 100% of 2015 ESA Investco, LLC's equity commitment since 2015 ESA Investco, LLC is consolidated by Generation (see Note 3 Variable Interest Entities for additional details). As of March 31, 2016, Generation's estimated commitment relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	<b>Total</b>
2016 <sup>(a)</sup>	\$ 271
2017	21
2018	7
Total	\$ 299

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(a) The noncontrolling interest holder of 2015 ESA Investco, LLC will contribute up to \$132 million in support of a portion of the remaining equity commitment.

**Commercial Commitments (All Registrants)**

The Registrants' commercial commitments as of March 31, 2016, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Letters of credit (non-debt) <sup>(a)</sup>	\$ 1,628	\$ 1,560	\$ 16	\$ 22	\$ 2	\$ 1	\$	\$	\$
Surety bonds <sup>(b)</sup>	950	852	10	9	10	16	9	4	3
Financing trust guarantees	628		200	178	250				
Nuclear insurance premiums <sup>(c)</sup>	3,056	3,056							
Guaranteed lease residual values <sup>(d)</sup>	20					20	6	8	5
Total commercial commitments	\$ 6,282	\$ 5,468	\$ 226	\$ 209	\$ 262	\$ 37	\$ 15	\$ 12	\$ 8

(a) Letters of credit (non-debt) Exelon and certain subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.

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

(c) Nuclear insurance premiums Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

(d) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be \$53 million, \$13 million of which is a guarantee by Pepco, \$17 million by DPL and \$14 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

**Nuclear Insurance (Exelon and Generation)**

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

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of March 31, 2016, the current liability limit per incident is \$13.5 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of March 31, 2016, the amount of nuclear energy liability insurance purchased is \$375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory



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

participation in a retrospective rating plan for power reactors (currently 103 reactors) resulting in an additional \$13.1 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is \$127.3 million, payable at no more than \$19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately \$2.7 billion, including CENG's related liability.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the \$13.5 billion limit for a single incident.

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Exelon 2015 Form 10-K for additional information on Generation's operations relating to CENG.

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

NEIL provides all risk property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of \$3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

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

**Environmental Issues (All Registrants)**

**General.** The Registrants' operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

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

ComEd, PECO, BGE and DPL have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

ComEd has identified 42 sites, 17 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 25 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2020.

PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 sites are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2021.

BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One former gas purification site is currently under investigation at the direction of the MDE. For more information, see the discussion of the Riverside site below.

DPL has identified 2 sites, 1 of which the remediation has been completed and approved by the MDE. Remediation work at the remaining site has been completed and an application has been submitted to the Delaware Department of Natural Resources and Environmental Control for approval.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. ComEd and PECO have recorded regulatory assets for the recovery of these costs. See Note 5 – Regulatory Matters for additional information regarding the associated regulatory assets. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. DPL has historically received recovery of actual clean-up costs in distribution rates.

As of March 31, 2016 and December 31, 2015, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

	<b>Total Environmental Investigation and Remediation Reserve</b>	<b>Portion of Total Related to MGP Investigation and Remediation<sup>(a)</sup></b>
<b>March 31, 2016</b>		
Exelon	\$ 399	\$ 298
Generation	68	
ComEd	263	261
PECO	36	34
BGE	3	2
PHI (Successor)	29	1
Pepco	25	
DPL	3	1



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

December 31, 2015	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation <sup>(a)</sup>
Exelon	\$ 369	\$ 301
Generation	63	
ComEd	266	264
PECO	37	35
BGE	3	2
PHI (Predecessor)	33	1
Pepco	24	
DPL	3	1
ACE	1	

(a) For BGE, includes reserve for Riverside, a gas purification site. See discussion below for additional information.

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

**Water Quality**

**Groundwater Contamination.** In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a \$1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Generation's remaining groundwater contamination reserve was \$11 million at March 31, 2016 and \$12 million at December 31, 2015.

**Benning Road Site NPDES Permit Limit Exceedances.** Pepco holds an NPDES permit issued by EPA with a July 19, 2009 effective date, which authorizes discharges from the Benning Road site, including the Pepco Energy Services generating facility previously located on the site that was deactivated in 2012 and has been demolished. The 2009 permit for the first time imposed numerical limits on the allowable concentration of certain metals in storm water discharged from the site into the Anacostia River as determined by EPA to be necessary to meet the applicable District of Columbia surface water quality standards. The permit contemplated that Pepco would meet these limits over time through the use of best management practices (BMPs). As of December 2012, Pepco completed the implementation of the first two phases of BMPs identified in a plan approved by EPA (consisting principally of installing metal absorbing filters to capture contaminants at storm water inlets, removing stored equipment from areas exposed to the weather, covering and painting exposed metal pipes, and covering and cleaning dumpsters). These measures were effective in reducing metal concentrations in storm water discharges, but were not sufficient to meet all of the numerical limits for metals. Most of the quarterly monitoring results since the issuance of the permit have shown exceedances of the limits for copper and zinc, as well as occasional exceedances for iron and lead.





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The NPDES permit was due to expire on June 19, 2014. Pepco submitted a permit renewal application on December 17, 2013. In November 2014, EPA advised Pepco that it will not renew the permit until the Benning Road site has come into compliance with the existing permit limits. The current permit remains in effect pending EPA's action on the renewal application. In December 2014, Pepco submitted a plan to EPA to implement the third phase of BMPs recommended in the original permit compliance plan with the objective of achieving full compliance with the permit limits for metals by the end of 2015 and Pepco immediately began to implement the additional BMPs in accordance with the plan. On September 1, 2015, Pepco submitted a report to EPA on the status of implementation of the third phase of BMPs. As of that date, Pepco had fully implemented most of the elements of the Phase 3 plan, including installation of upgraded storm water inlet controls (filters and booms), enhanced inspection and maintenance of inlets, removal of materials and equipment from exposure to storm water, and removal of accumulated sediments from the underground storm drains. The sampling results from the third quarter of 2015 showed compliance with all of the permit limits. However, more recent sampling results continued to show modest exceedances for copper and zinc. As confirmed by this latest sampling, because the permit limits are low and site conditions are subject to variation, Pepco has concluded that some form of storm water treatment prior to discharge will be necessary to ensure ongoing compliance with all permit limits and has begun the process of evaluating treatment options. The nature and scope of the necessary treatment system, and the amount of the associated capital expenditures, will not be known until Pepco has completed the evaluation and design process.

Pepco has been engaged in discussions with representatives from EPA and the DOJ regarding permit compliance. On October 30, 2015, EPA filed a Clean Water Act civil enforcement action against Pepco in federal district court. Pepco expects that this enforcement action will be resolved through a consent decree that will (i) establish further requirements to achieve compliance with the permit limits, including the design and installation of an appropriate storm water treatment system as noted above, and (ii) include civil penalties for past noncompliance. While the amount of civil penalties is not known at this time, and Pepco does not expect the amount of such penalties to have a material adverse effect on Exelon's, PHI's and Pepco's consolidated financial condition, results of operations or cash flows, Pepco has established what it believes is an appropriate reserve for this matter.

Pepco and EPA are currently in discussions regarding the terms of the contemplated consent decree, and it is anticipated that the parties will finalize the consent decree before the end of 2016. In response to a joint motion by the parties, the court has extended the deadline for Pepco to answer the complaint to May 16, 2016, to give the parties time to work towards agreement on the terms of a consent decree. The parties contemplate seeking a further extension if necessary to complete their negotiations. Once executed by the parties, the consent decree will be filed with the court for review and approval following a period for public comment.

On March 14, 2016, the court granted a motion by the Anacostia Riverkeeper to intervene in this case as a plaintiff along with EPA. As an intervenor, the Anacostia Riverkeeper will be entitled to file a brief commenting on the proposed consent decree and to appeal any decision by the court to approve the consent decree over the Anacostia Riverkeeper's objection, but its participation is not expected to materially affect the progress or outcome of the consent decree negotiations.

***Potomac River Mineral Oil Release.*** In January 2011, there was a release of 4,500 gallons of non-toxic mineral oil at Pepco's Potomac River substation in Alexandria, Virginia into the Potomac River.

In March 2014, Pepco and the District of Columbia Department of Energy and Environment (DOEE) (formerly The District of Columbia Department of the Environment) entered into a consent decree to resolve a threatened DOEE enforcement action, the terms of which include a combination of a civil penalty and a Supplemental Environmental Project (SEP) with a total cost to Pepco of \$875,000. The consent decree was

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

approved and entered by the District of Columbia Superior Court on April 4, 2014. Pepco has paid the \$250,000 civil penalty imposed under the consent decree and, pursuant to the consent decree, has made a one-time donation in the amount of \$25,000 to the Northeast Environmental Enforcement Training Fund, Inc., a non-profit organization that funds scholarships for environmental enforcement training. The consent decree confirmed that no further actions are required by Pepco to investigate, assess or remediate impacts to the river from the mineral oil release. To implement the SEP, Pepco has entered into an agreement with Living Classrooms Foundation, Inc., a non-profit educational organization, pursuant to which Pepco will provide \$600,000 to fund the design, installation and operation of a trash collection system at a storm water outfall that drains to the Anacostia River. DOEE approved the design for the trash collection system and efforts to secure necessary permits are in progress. Pepco expects that this system will be constructed and placed into operation by the end of 2016, which will satisfy Pepco's obligations under the consent decree. On September 11, 2015, Pepco and DOEE filed a joint report with the D.C. Superior Court on the status of the trash cage project and other elements of the consent decree. The court accepted that report and scheduled the next status hearing in this matter for September 23, 2016.

The consent decree did not resolve potential claims under federal law for natural resource damages resulting from the mineral oil release. Pepco has engaged in separate discussions with DOEE and the federal resource trustees regarding the settlement of a possible natural resource damages claim under federal law. In July 2013, Pepco submitted a natural resource damage assessment to DOEE and the federal trustees that proposed monetary compensation for such damages in the range of \$106,000 to \$161,000. By letter dated September 16, 2015, the U.S. Department of Interior, on behalf of the trustees, made a confidential counter-proposal for settlement of the natural resource damage claim. Pepco has engaged in subsequent discussions with the trustees and believes that the parties are close to reaching an agreement to settle the claims. Based on the discussions to date, Exelon, PHI and Pepco do not believe that the resolution of the natural resource damages claim will have a material adverse effect on their respective financial condition, results of operations or cash flows.

As a result of the mineral oil release, Pepco implemented certain interim operational changes to the secondary containment systems at the facility, which involve pumping accumulated storm water to an above-ground holding tank for off-site disposal. Pepco is continuing to use the above-ground holding tank to manage storm water from the secondary containment system while it evaluates other technical and regulatory options.

***Solid and Hazardous Waste***

**Cotter Corporation.** The EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study, that are now scheduled to be completed in mid-2016 to enable the EPA to propose a remedy for public comment by the end of 2016. Thereafter the EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the EPA would require a complete excavation is remote. The EPA is also reviewing a partial excavation remedy; however, until the current

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

sampling is concluded there is no basis to determine the likelihood and estimate of a partial excavation remedy. The current estimated cost of the landfill cover remediation for the site is approximately \$60 million, which will be allocated among all PRPs. Recent investigation has identified a number of other parties who may be PRPs and could be liable to contribute to the final remedy. Further investigation is underway. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action. The second action involved EPA's public statement that it will require the PRPs to construct a barrier wall in an adjacent landfill to prevent a subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, EPA has not provided sufficient details related to the basis for and the requirements and design of a barrier wall to enable Generation to determine the likelihood such a remedy will ultimately be implemented, assess the degree to which Generation may have liability as a potentially responsible party, or develop a reasonable estimate of the potential incremental costs. It is reasonably possible, however, that resolution of this matter could have a material, unfavorable impact on Generation's and Exelon's future results of operations and cash flows. Finally, one of the other PRPs, the landfill owner and operator of the adjacent landfill, has indicated that it will be making a contribution claim against Cotter for costs that it has incurred to prevent the subsurface fire from spreading to those areas of the West Lake Landfill where radiological materials are believed to have been disposed. At this time, Generation and Exelon do not possess sufficient information to assess this claim and are therefore unable to determine the impact on their future results of operations and cash flows.

On February 2, 2016, the U.S. Senate passed a bill to transfer remediation authority over the West Lake Landfill from the EPA to the U.S. Army Corps of Engineers, under the Formerly Utilized Sites Remedial Action Program (FUSRAP). Such legislation would become final upon passage in the U.S. House of Representatives and the signature of the President, and be subject to annual funding appropriations in the U.S. Budget. Remediation under FUSRAP would not alter the liability of the PRPs, but could delay the determination of a final remedy and its implementation.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the FUSRAP. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately \$90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2016 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

Commencing in February 2012, 41 lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon, Generation and ComEd, all of which were subsequently dismissed from the case, and Cotter, which remains a defendant. The suits allege that individuals

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

living in the North St. Louis area developed some form of cancer due to Cotter's negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. The court has dismissed the lawsuits filed by 30 of the plaintiffs. Pre-trial motions and discovery are proceeding in the remaining cases and a proposed pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation and ComEd cannot estimate a range of loss, if any.

**68<sup>th</sup> Street Dump.** In 1999, the EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the EPA are still subject to EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of \$50 million to \$64 million. On September 30, 2013, EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by EPA is consistent with the PRPs estimated range of costs noted above. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs.

**Rossville Ash Site.** The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately \$9 million which has been fully reserved as of March 31, 2016.

**Sauer Dump.** On May 30, 2012, BGE was notified by the EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the EPA is seeking recovery from the PRPs of \$1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRPs signed an Administrative Settlement Agreement and Order on Consent with the EPA which requires the PRPs to conduct a remedial investigation (RI) and feasibility study (FS) at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

**Riverside.** In 2013, the MDE, at the request of EPA, conducted a site inspection and limited environmental sampling of certain portions of the 170 acre Riverside property owned by BGE. The site consists of several different parcels with different current and historical uses. The sampling included soil and groundwater samples for a number of potential environmental contaminants. The sampling confirmed the existence of contaminants consistent with the known historical uses of the various portions of the site. In March 2014, the MDE requested that BGE conduct an investigation of three specific areas of the site, and a site-wide investigation of soils,

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sediment, groundwater, and surface water to complement the MDE sampling. The field investigation was completed in January 2015, and a final report was provided to MDE on June 2, 2015. On November 3, 2015, MDE provided BGE with its comments and recommendations on the report which require BGE to conduct further investigation and sampling at the site to better delineate the nature and extent of historic contamination, including off-site sediment and soil sampling. MDE did not request any interim remediation at this time. Upon completion of the investigation to date, BGE has established what it believes is an appropriate reserve. As the investigation and potential remediation proceed, it is possible that additional reserves could be established, in amounts that could be material to BGE.

***Benning Road Site.*** In September 2010, PHI received a letter from EPA identifying the Benning Road site as one of six land-based sites potentially contributing to contamination of the lower Anacostia River. A portion of the site was formerly the location of a Pepco Energy Services electric generating facility. That generating facility was deactivated in June 2012 and plant structure demolition was completed in July 2015. The remaining portion of the site consists of a Pepco transmission and distribution service center that remains in operation. The principal contaminants allegedly of concern are polychlorinated biphenyls and polycyclic aromatic hydrocarbons. In December 2011, the U.S. District Court for the District of Columbia approved a consent decree entered into by Pepco and Pepco Energy Services with the DOEE, which requires Pepco and Pepco Energy Services to conduct a RI/FS for the Benning Road site and an approximately 10 to 15 acre portion of the adjacent Anacostia River. The RI/FS will form the basis for the remedial actions for the Benning Road site and for the Anacostia River sediment associated with the site. The consent decree does not obligate Pepco or Pepco Energy Services to pay for or perform any remediation work, but it is anticipated that DOEE will look to Pepco and Pepco Energy Services to assume responsibility for cleanup of any conditions in the river that are determined to be attributable to past activities at the Benning Road site.

The initial RI field work began in January 2013 and was completed in December 2014. In addition, in conjunction with the power plant demolition activities, Pepco and Pepco Energy Services collected soil samples adjacent to and beneath the concrete basins for the dismantled cooling towers for the generating facility. This sampling showed localized areas of soil contamination associated with the cooling tower basins, and, beginning in the second quarter of 2016, Pepco and Pepco Energy Services expect to implement a plan approved by DOEE to remove contaminated soil in conjunction with the demolition and removal of the concrete basins. On April 30, 2015, Pepco and Pepco Energy Services submitted a draft RI Report to DOEE. After review, DOEE determined that additional field investigation and data analysis is required to complete the RI process (much of which is beyond the scope of the original DOEE-approved RI work plan). In the meantime, Pepco and Pepco Energy Services revised the draft RI Report to address DOEE's comments and DOEE released the draft RI Report for public review on February 29, 2016. The additional field investigation and data analysis will proceed later in 2016 according to a schedule to be developed by Pepco and Pepco Energy Services and approved by DOEE. Once the additional RI work has been completed, Pepco and Pepco Energy Services will issue a draft final RI report for review and comment by DOEE and the public. Pepco and Pepco Energy Services will then proceed with an FS to evaluate possible remedial alternatives. This effort also may include a treatability study to evaluate the effectiveness of potential remedial options. Once the FS evaluation has been completed, Pepco and Pepco Energy Services will prepare and submit a draft FS Report for review and comment by DOEE and the public. Thereafter, Pepco and Pepco Energy Services will revise the draft FS Report as appropriate to address comments received and will submit a final FS Report to DOEE.

Upon DOEE's approval of the final remedial investigation and feasibility study Reports, Pepco and Pepco Energy Services will have satisfied their obligations under the consent decree. At that point, DOEE will prepare a Proposed Plan regarding further response actions based on the results of the remedial investigation and feasibility study. After considering public comment on the Proposed Plan, DOEE will issue a Record of Decision identifying any further response actions determined to be necessary.

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DOEE, Pepco and Pepco Energy Services must submit their next joint status report to the court regarding progress on the RI/FS by May 24, 2016. PHI, Pepco and Pepco Energy Services have determined that a loss associated with this matter for PHI, Pepco and Pepco Energy Services is probable and have estimated that the costs of remediation are in the range of approximately \$9 million to \$13 million. An estimated liability for this issue has been accrued.

**Anacostia River Tidal Reach.** Contemporaneous with the Benning RI/FS being performed by Pepco and Pepco Energy Services, DOEE has been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the confluence of the Anacostia and Potomac Rivers. On March 18, 2016, DOEE released a draft of the river-wide RI Report for public review and comment. The river-wide RI incorporated the results of the river sampling performed by Pepco and Pepco Energy Services as part of the Benning RI/FS, as well as similar sampling efforts conducted by owners of other sites adjacent to this segment of the river and supplemental river sampling conducted by DOEE's contractor. DOEE has asked Pepco, along with parties responsible for other sites along the river, to participate in a Consultative Working Group to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning site resulting from the Benning RI/FS. Pepco will review the draft river-wide RI report and consider its response to this request during the second quarter of 2016. At this time, it is not possible to predict the nature or extent of Pepco's possible participation in the river-wide RI/FS process, or its potential exposure for response costs beyond those associated with the Benning RI/FS component of the river-wide initiative.

**Conectiv Energy Wholesale Power Generation Sites.** In July 2010, PHI sold the wholesale power generation business of Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries (Conectiv Energy) to Calpine Corporation (Calpine). Under New Jersey's Industrial Site Recovery Act (ISRA), the transfer of ownership triggered an obligation on the part of Conectiv Energy to remediate any environmental contamination at each of the nine Conectiv Energy generating facility sites located in New Jersey. Under the terms of the sale, Calpine has assumed responsibility for performing the ISRA-required remediation and for the payment of all related ISRA compliance costs up to \$10 million. PHI is obligated to indemnify Calpine for any ISRA compliance remediation costs in excess of \$10 million. According to PHI's estimates, the costs of ISRA-required remediation activities at the 9 generating facility sites located in New Jersey are in the range of approximately \$7 million to \$18 million, and PHI has established an appropriate accrual for its share of the estimated clean-up costs.

In September 2011, PHI received a request for data from the EPA regarding operations at the Deepwater generating facility in New Jersey (which was included in the sale to Calpine) between February 2004 and July 1, 2010, to demonstrate compliance with the Clean Air Act's new source review permitting program. PHI responded to the data request. Under the terms of the Calpine sale, PHI is obligated to indemnify Calpine for any failure of PHI, on or prior to the closing date of the sale, to comply with environmental laws attributable to the construction of new, or modification of existing, sources of air emissions. At this time, Exelon and PHI do not expect this inquiry to have a material adverse effect on their consolidated financial condition, results of operations or cash flows.

**Rock Creek Mineral Oil Release.** In late August 2015, a Pepco underground transmission line in the District of Columbia suffered a breach, resulting in the release of non-toxic mineral oil surrounding the transmission line into the surrounding soil, and a small amount reached Rock Creek through a storm drain. Pepco notified regulatory authorities, and Pepco and its spill response contractors placed booms in Rock Creek, blocked the storm drain to prevent the release of mineral oil into the creek and commenced remediation of soil around the transmission line and the Rock Creek shoreline. Pepco estimates that approximately 6,100 gallons of mineral oil

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were released and that its remediation efforts recovered approximately 80% of the amount released. Pepco's remediation efforts are ongoing under the direction of the DOEE, including the requirements of a February 29, 2016 compliance order which requires Pepco to prepare a full incident investigation report and prepare a removal action work plan to remove all impacted soils in the vicinity of the storm drain outfall, and in collaboration with the National Park Service, the Smithsonian Institution/National Zoo and EPA. Pepco's investigation presently indicates that the damage to Pepco's facilities occurred prior to the release of mineral oil when third-party excavators struck the Pepco underground transmission line while installing cable for another utility.

To the extent recovery is available against any party who contributed to this loss, PHI and Pepco will pursue such action. Exelon, PHI and Pepco continue to investigate the cause of the incident, the parties involved, and legal responsibility under District of Columbia law, but do not believe that the remediation costs to resolve this matter will have a material adverse effect on their respective financial condition, results of operations or cash flows.

**Peck Iron and Metal Site.** EPA informed Pepco in a May 2009 letter that Pepco may be a PRP under CERCLA with respect to the cleanup of the Peck Iron and Metal site in Portsmouth, Virginia, and for costs EPA has incurred in cleaning up the site. The EPA letter states that Peck Iron and Metal purchased, processed, stored and shipped metal scrap from military bases, governmental agencies and businesses and that the Peck Iron and Metal scrap operations resulted in the improper storage and disposal of hazardous substances. EPA bases its allegation on its belief that Pepco was a customer at the site. Pepco has advised EPA by letter that its records show no evidence of any sale of scrap metal by Pepco to the site. Even if EPA has such records and such sales did occur, Pepco believes that any such scrap metal sales may be entitled to the recyclable material exemption from CERCLA liability. In September 2011, EPA initiated a RI/FS for the site using Federal funds. Pepco cannot at this time estimate an amount or range of reasonably possible loss associated with this RI/FS, any remediation activities to be performed at the site or any other costs that EPA might seek to impose on Pepco.

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

Exelon, PHI and Pepco have determined that a loss associated with this matter is probable and have estimated that the costs for implementation of a closure plan and cap on the site are in the range of approximately \$3 million to \$6 million. Exelon, PHI and Pepco believe that the costs incurred in this matter will be recoverable from NRG under the 2000 sale agreement.

**Litigation and Regulatory Matters****Asbestos Personal Injury Claims (Exelon, Generation, ComEd, PECO and BGE)**

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

At March 31, 2016 and December 31, 2015, Generation had reserved approximately \$93 million and \$95 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2016, approximately \$21



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

million of this amount related to 234 open claims presented to Generation, while the remaining \$72 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary.

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

On November 4, 2015, the Illinois Supreme Court found that the provisions of the Illinois Workers Compensation Act and the Workers Occupational Diseases Act barred an employee from bringing a direct civil action against an employer for latent diseases, including asbestos-related diseases that fall outside the 25-year limit of the statute of repose. The Illinois Supreme Court's ruling reversed previous rulings by the Illinois Court of Appeals, which initially ruled that the Illinois Worker's Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker's Compensation claim. Exelon, Generation, and ComEd have not recorded an increase to the asbestos-related bodily injury liability as of March 31, 2016.

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

**BGE.** Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of premises liability, alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 452 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

the identity of the facilities at which the plaintiffs allegedly worked as contractors;

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

the names of the plaintiffs' employers;

the dates on which and the places where the exposure allegedly occurred; and

the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

***Continuous Power Interruption (Exelon and ComEd)***

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. As of March 31, 2016 and December 31, 2015, ComEd did not have any material liabilities recorded for these storm events.

***Baltimore City Franchise Taxes (Exelon and BGE)***

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE has reviewed the City's claim and believes that it lacks merit. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

***General (All Registrants)***

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

***Income Taxes (Exelon, Generation, ComEd, PECO and BGE)***

See Note 15 - Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

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

**19. Supplemental Financial Information (All Registrants)***Supplemental Statement of Operations Information*

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31, 2016								Successor	Predecessor
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016
<b>Other, Net</b>										
Decommissioning-related activities:										
Net realized income on decommissioning trust funds <sup>(a)</sup>										
Regulatory agreement units	\$ 34	\$ 34	\$	\$	\$	\$	\$	\$	\$	\$
Non-regulatory agreement units	21	21								
Net unrealized gains on decommissioning trust funds										
Regulatory agreement units	79	79								
Non-regulatory agreement units	52	52								
Net unrealized gains on pledged assets										
Zion Station decommissioning	2	2								
Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>	(95)	(95)								
Total decommissioning-related activities	93	93								
Investment income	6	1			1 <sup>(c)</sup>					
Long-term lease income	4									
Interest income related to uncertain income tax positions	1					1		1		
AFUDC Equity	8		2	2	3	4	1	2	1	7
Loss on debt extinguishment	(2)	(2)								
Other	4	1	2			4	2	1	1	(11)
Other, net	\$ 114	\$ 93	\$ 4	\$ 2	\$ 4	\$ 9	\$ 3	\$ 4	\$ 2	\$ (4)

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

	Three Months Ended March 31, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
<b>Other, Net</b>									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds <sup>(a)</sup>									
Regulatory agreement units	\$ 71	\$ 71	\$	\$	\$	\$	\$	\$	\$
Non-regulatory agreement units	29	29							
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	48	48							
Non-regulatory agreement units	40	40							
Net unrealized gains on pledged assets									
Zion Station decommissioning	10	10							
Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>	(106)	(106)							
Total decommissioning-related activities	92	92							
Investment income	1	1			1 <sup>(c)</sup>				
Long-term lease income	4								
Interest income related to uncertain income tax positions		1							
AFUDC Equity	5			2	3	4	3		1
Terminated interest rate swaps <sup>(d)</sup>	(23)	3							
Other	1	(3)	3			5	2	2	
Other, net	\$ 80	\$ 94	\$ 3	\$ 2	\$ 4	\$ 9	\$ 5	\$ 2	\$ 1

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 16 Asset Retirement Obligations of the Exelon 2015 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

(c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information regarding the rate stabilization deferral.

(d) In January 2015, in connection with Generation's \$750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments were probable not to occur. As a result, \$26 million of anticipated payments were reclassified from AOCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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The following utility taxes are included in revenues and expenses for the three months ended March 31, 2016 and 2015. Generation's utility tax expense represents gross receipts tax related to its retail operations and the utility registrants' utility tax expense represents municipal and state utility taxes and gross receipts taxes related to their operating revenues. The offsetting collection of utility taxes from customers is recorded in revenues on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

	Exelon	Generation	Three Months Ended March 31, 2016						Successor	Predecessor
			ComEd	PECO	BGE	Pepco	DPL	ACE	March 24, 2016 to March 31, 2016 PHI	January 1, 2016 to March 23, 2016 PHI
Utility taxes	\$ 153	\$ 28	\$ 59	\$ 35	\$ 24	\$ 79	\$ 5	\$	\$ 7	\$ 77

	Exelon	Generation	ComEd	PECO	BGE	Three Months Ended March 31, 2015			
						PHI	Pepco	DPL	ACE
Utility taxes	\$ 148	\$ 27	\$ 62	\$ 35	\$ 24	\$ 85	\$ 80	\$ 5	\$

**Supplemental Cash Flow Information**

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the three months ended March 31, 2016 and 2015:

	Exelon	Generation	Three Months Ended March 31, 2016						Successor	Predecessor
			ComEd	PECO	BGE	Pepco	DPL	ACE	March 24, 2016 to March 31, 2016 PHI	January 1, 2016 to March 23, 2016 PHI
<b>Depreciation, amortization, accretion and depletion</b>										
Property, plant and equipment	\$ 606	\$ 278	\$ 170	\$ 60	\$ 75	\$ 42	\$ 27	\$ 20	\$ 9	\$ 94
Amortization of regulatory assets	65		19	7	34	33	12	20	5	58
Amortization of intangible assets, net	14	11								
Amortization of energy contract assets and liabilities <sup>(a)</sup>	(14)	(14)								
Nuclear fuel <sup>(b)</sup>	283	283								
ARO accretion <sup>(c)</sup>	109	109								
Total depreciation, amortization, accretion and depletion	\$ 1,063	\$ 667	\$ 189	\$ 67	\$ 109	\$ 75	\$ 39	\$ 40	\$ 14	\$ 152

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

	Three Months Ended March 31, 2015								
	Exelon	Generation	ComEd	PECO	BGE	PHI <i>Predecessor</i>	Pepco	DPL	ACE
<b>Depreciation, amortization, accretion and depletion</b>									
Property, plant and equipment	\$ 540	\$ 242	\$ 154	\$ 58	\$ 71	\$ 96	\$ 40	\$ 25	\$ 19
Amortization of regulatory assets	58		21	4	35	59	22	14	24
Amortization of intangible assets, net	12	12							
Amortization of energy contract assets and liabilities <sup>(a)</sup>	(31)	(32)							
Nuclear fuel <sup>(b)</sup>	272	272							
ARO accretion <sup>(c)</sup>	97	97							
Total depreciation, amortization, accretion and depletion	\$ 948	\$ 591	\$ 175	\$ 62	\$ 106	\$ 155	\$ 62	\$ 39	\$ 43

(a) Included in Operating revenues or Purchased power and fuel expense on the Registrants Consolidated Statements of Operations and Comprehensive Income.

(b) Included in Purchased power and fuel expense on the Registrants Consolidated Statements of Operations and Comprehensive Income.

(c) Included in Operating and maintenance expense on the Registrants Consolidated Statements of Operations and Comprehensive Income.

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	Three Months Ended March 31, 2016							Successor	Predecessor	
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
<b>Other non-cash operating activities:</b>										
Pension and non-pension postretirement benefit costs	\$ 136	\$ 54	\$ 41	\$ 8	\$ 16	\$ 8	\$ 5	\$ 4	\$ 3	\$ 23
Loss from equity method investments	3	3								
Provision for uncollectible accounts	41	6	9	16	12	5	5	7	(2)	16
Stock-based compensation costs	44									3
Other decommissioning-related activity <sup>(a)</sup>	(55)	(55)								
Energy-related options <sup>(b)</sup>	(9)	(9)								
Amortization of regulatory asset related to debt costs	1		1			1				1
Amortization of rate stabilization deferral	20				20	1	4			5
Amortization of debt fair value adjustment	(3)	(3)								
Discrete impacts from EIMA <sup>(c)</sup>	(14)		(14)							
Amortization of debt costs	8	4	1	1	1					
Provision for excess and obsolete inventory	1	1				1	1	1		1
Merger-related commitments <sup>(d)(e)</sup>	503	3				138	100	120	358	
Severance costs	69	4							52	
Asset retirement costs							4	2		
Lower of cost or market inventory adjustment	36	36								
Other	23	7	(6)	(1)	(5)	(1)	(1)	(2)	(1)	(3)
<b>Total other non-cash operating activities</b>	<b>\$ 804</b>	<b>\$ 51</b>	<b>\$ 32</b>	<b>\$ 24</b>	<b>\$ 44</b>	<b>\$ 153</b>	<b>\$ 118</b>	<b>\$ 132</b>	<b>\$ 410</b>	<b>\$ 46</b>
<b>Non-cash investing and financing activities:</b>										
Change in capital expenditures not paid	\$ (290)	\$ (234)	\$ 25	\$ (65)	\$ (4)	\$ 9	\$ 8	\$ (9)	\$ (7)	\$ 11
Fair value of net assets contributed to Generation in connection with the PHI Merger, net of cash <sup>(d)(f)</sup>		119								
Fair value of net assets distributed to Exelon in connection with the PHI Merger, net of cash <sup>(d)(f)</sup>									127	
Fair value of pension obligation transferred in connection with the PHI Merger									45	
Assumption of member purchase liability									29	
Change in PPE related to ARO update	62	62								
Indemnification of like-kind exchange position <sup>(g)</sup>			1							
Non-cash financing of capital projects	31	31								

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	Three Months Ended March 31, 2015								
	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
<b>Other non-cash operating activities:</b>									
Pension and non-pension postretirement benefit costs	\$ 159	\$ 67	\$ 52	\$ 10	\$ 16	\$ 24	\$ 8	\$ 4	\$ 4
Provision for uncollectible accounts	84	4	22	33	25	16	4	7	5
Stock-based compensation costs	39					3			
Other decommissioning-related activity <sup>(a)</sup>	(44)	(44)							
Energy-related options <sup>(b)</sup>	9	9							
Amortization of regulatory asset related to debt costs	3		2	1		1	1		
Amortization of rate stabilization deferral	25				25	11	10	1	
Amortization of debt fair value adjustment	(9)	(4)							
Discrete impacts from EIMA <sup>(c)</sup>	46		46						
Amortization of debt costs	18	4	1	1	1				
Lower of cost or market inventory adjustment	10	10							
Other	4	(1)	3	(1)	(3)	2			(1)
Total other non-cash operating activities	\$ 344	\$ 45	\$ 126	\$ 44	\$ 64	\$ 57	\$ 23	\$ 12	\$ 8
<b>Non-cash investing and financing activities:</b>									
Change in PPE related to ARO update	56	56							
Indemnification of like-kind exchange position <sup>(g)</sup>			2						

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 16 Asset Retirement Obligations of the Exelon 2015 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

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

(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 Regulatory Matters for more information.

(d) See Note 4 Mergers, Acquisitions and Dispositions for additional information related to the merger with PHI.

(e) Excludes \$5 million of forgiveness of Accounts receivable related to merger commitments recorded in connection with the PHI Merger, the balance is included within Provision for uncollectible accounts.

(f) Immediately following closing of the PHI Merger, the net assets associated with PHI's unregulated business interests were distributed by PHI to Exelon. Exelon contributed a portion such net assets to Generation.

(g) See Note 11 Income Taxes for discussion of the like-kind exchange tax position.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Supplemental Balance Sheet Information**

The following tables provide additional information about assets and liabilities of the Registrants as of March 31, 2016 and December 31, 2015.

March 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
<b>Property, plant and equipment:</b>									
Accumulated depreciation and amortization	\$ 16,776 <sup>(a)</sup>	\$ 8,950 <sup>(a)</sup>	\$ 3,716	\$ 3,139	\$ 3,069	\$ 4	\$ 2,960	\$ 1,140	\$ 983
<b>Accounts receivable:</b>									
Allowance for uncollectible accounts	\$ 351	\$ 73	\$ 82	\$ 90	\$ 53	\$ 53	\$ 16	\$ 19	\$ 18

December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	Predecessor PHI	Pepco	DPL	ACE
<b>Property, plant and equipment:</b>									
Accumulated depreciation and amortization	\$ 16,375 <sup>(b)</sup>	\$ 8,639 <sup>(b)</sup>	\$ 3,710	\$ 3,101	\$ 3,016	\$ 5,341	\$ 2,929	\$ 1,139	\$ 968
<b>Accounts receivable:</b>									
Allowance for uncollectible accounts	\$ 284	\$ 77	\$ 75	\$ 83	\$ 49	\$ 56	\$ 17	\$ 17	\$ 17

(a) Includes accumulated amortization of nuclear fuel in the reactor core of \$3,008 million.

(b) Includes accumulated amortization of nuclear fuel in the reactor core of \$2,861 million.

**PECO Installment Plan Receivables (Exelon and PECO)**

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was \$14 million and \$15 million as of March 31, 2016 and December 31, 2015, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 Significant Accounting Policies of the Exelon 2015 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at March 31, 2016 of \$13 million consists of \$1 million, \$3 million and \$9 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2015 of \$15 million consists of \$1 million, \$3 million and \$11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of March 31, 2016 and December 31, 2015 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 Significant Accounting Policies of the Exelon 2015 Form 10-K.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****20. Segment Information (All Registrants)**

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

In the first quarter of 2016, following the consummation of the PHI Merger, three new reportable segments were added: Pepco, DPL and ACE. As a result, Exelon has twelve reportable segments, which include ComEd, PECO, BGE, PHI's three reportable segments consisting of Pepco, DPL, and ACE, and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as "Other Power Regions", which includes activities in the South, West and Canada. ComEd, PECO, BGE, Pepco, DPL and ACE each represent a single reportable segment, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE's CODMs evaluate the performance of and allocate resources to ComEd, PECO, BGE, Pepco, DPL and ACE based on net income and return on equity.

Effective with the consummation of the PHI Merger, PHI's reportable segments have changed based on the information used by the CODM to evaluate performance and allocate resources. PHI's reportable segments consist of Pepco, DPL and ACE. PHI's Predecessor periods' segment information has been recast to conform to the current presentation. The reclassification of the segment information did not impact PHI's reported consolidated revenues or net income. PHI's CODM evaluates the performance of and allocates resources to Pepco, DPL and ACE based on net income and return on equity.

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

Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

New York represents operations within ISO-NY, which covers the state of New York in its entirety.

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

Other Power Regions:

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South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado and parts of New Mexico, Wyoming and South Dakota.

Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

An analysis and reconciliation of the Registrants reportable segment information to the respective information in the consolidated financial statements for the three months ended March 31, 2016 and 2015 is as follows:

**Three Months Ended March 31, 2016 and 2015**

	Generation <sup>(a)</sup>	ComEd	PECO	BGE	Successor PHI <sup>(b)</sup>	Other <sup>(c)</sup>	Intersegment Eliminations	Exelon
<b>Operating revenues<sup>(d)</sup>:</b>								
2016								
Competitive businesses electric revenues	\$ 3,695	\$	\$	\$	\$	\$	\$ (266)	\$ 3,429
Competitive businesses natural gas revenues	822							822
Competitive businesses other revenues	222							222
Rate-regulated electric revenues		1,249	644	680	90		(6)	2,657
Rate-regulated natural gas revenues			197	249	3		(5)	444
Shared service and other revenues					12	405	(418)	(1)
2015								
Competitive businesses electric revenues	\$ 4,397	\$	\$	\$	\$	\$	\$ (209)	\$ 4,188
Competitive businesses natural gas revenues	1,124							1,124
Competitive businesses other revenues	319						(1)	318
Rate-regulated electric revenues		1,185	677	713			(1)	2,574
Rate-regulated natural gas revenues			308	323			(7)	624
Shared service and other revenues						318	(316)	2
<b>Intersegment revenues<sup>(e)</sup>:</b>								
2016	\$ 266	\$ 5	\$ 1	\$ 5	\$ 12	\$ 405	\$ (695)	\$ (1)
2015	210	1		7		317	(533)	2
<b>Net income (loss):</b>								
2016	\$ 257	\$ 115	\$ 124	\$ 101	\$ (309)	\$ (164)	\$ (1)	\$ 123
2015	485	90	139	109		(84)	(1)	738
<b>Total assets:</b>								
March 31, 2016	\$ 47,002	\$ 26,887	\$ 10,462	\$ 8,361	\$ 20,932	\$ 9,751	\$ (11,653)	\$ 111,742
December 31, 2015	46,529	26,532	10,367	8,295		15,389	(11,728)	95,384

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the three months ended March 31, 2016 include revenue from sales to PECO of \$79 million and sales to BGE of \$173 million in the Mid-Atlantic region, and sales to ComEd of \$5 million in the Midwest region. For the three months ended March 31, 2015, intersegment revenues for Generation include revenue from sales to PECO of \$63 million and sales to BGE of \$138 million in the Mid-Atlantic region, and sales to ComEd of \$9 million in the Midwest region. For the Successor period of March 24, 2016 to March 31, 2016, intersegment revenues for Generation include revenue from sales to Pepco of \$6 million, sales to DPL of \$4 million, and sales to ACE of \$1 million in the Mid-Atlantic region.



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

- (b) Amounts included represent activity for the PHI's successor period, March 24, 2016 through March 31, 2016. PHI includes the three reportable segments: Pepco, DPL and ACE. See tables below for PHI's predecessor periods, including Pepco, DPL and ACE, for January 1, 2016 to March 23, 2016 and for the three months ended March 31, 2015.
- (c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.
- (d) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 19 Supplemental Financial Information for total utility taxes for the three months ended March 31, 2016 and 2015.
- (e) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

**Generation total revenues:**

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	Revenues from external customers <sup>(a)</sup>	Intersegment revenues	Total Revenues	Revenues from external customers <sup>(a)(c)</sup>	Intersegment revenues <sup>(c)</sup>	Total Revenues <sup>(c)</sup>
Mid-Atlantic	\$ 1,532	\$ (12)	\$ 1,520	\$ 1,556	\$ (43)	\$ 1,513
Midwest	1,089	6	1,095	1,276		1,276
New England	471	(1)	470	865	(6)	859
New York	218	(15)	203	307	3	310
ERCOT	163		163	181	(1)	180
Other Power Regions	222	1	223	212	2	214
<b>Total Revenues for Reportable Segments</b>	<b>3,695</b>	<b>(21)</b>	<b>3,674</b>	<b>4,397</b>	<b>(45)</b>	<b>4,352</b>
Other <sup>(b)</sup>	1,044	21	1,065	1,443	45	1,488
<b>Total Generation Consolidated Operating Revenues</b>	<b>\$ 4,739</b>	<b>\$</b>	<b>\$ 4,739</b>	<b>\$ 5,840</b>	<b>\$</b>	<b>\$ 5,840</b>

- (a) Includes all wholesale and retail electric sales to third parties and affiliated sales to the Utility Registrants.
- (b) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a \$20 million and \$40 million increase to revenues for the amortization of intangible assets related to commodity contracts recorded at fair value for the three months ended March 31, 2016 and 2015, respectively, unrealized mark-to-market gains of \$63 million and \$154 million for the three months ended March 31, 2016 and 2015, respectively, and elimination of intersegment revenues.
- (c) Exelon corrected an error in the March 31, 2015 balances within Intersegment Revenue and Revenue from external customers for an overstatement of \$43 million of Intersegment Revenue for Reportable Segments for the three months ended March 31, 2015, an understatement of Revenue from external customers for Reportable Segments of \$43 million for the three months ended March 31, 2015, an understatement of \$43 million of Intersegment Revenue for Other for the three months ended March 31, 2015, and an overstatement of Revenue from external customers for Other of \$43 million for the three months ended March 31, 2015. This error is not considered material to any prior period, and there is no impact to Total Revenues.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Generation total revenues net of purchased power and fuel expense:**

	Three Months Ended March 31, 2016			Three Months Ended March 31, 2015		
	RNF from external customers <sup>(a)</sup>	Intersegment RNF	Total RNF	RNF from external customers <sup>(a)(c)</sup>	Intersegment RNF <sup>(c)</sup>	Total RNF <sup>(c)</sup>
Mid-Atlantic	\$ 832	\$ 9	\$ 841	\$ 808	\$ (21)	\$ 787
Midwest	715	3	718	709	(6)	703
New England	86	(5)	81	182	(24)	158
New York	141	(11)	130	169	20	189
ERCOT	81	(20)	61	88	(33)	55
Other Power Regions	86	(10)	76	72	(26)	46
Total Revenues net of purchased power and fuel expense for Reportable Segments	1,941	(34)	1,907	2,028	(90)	1,938
Other <sup>(b)</sup>	356	34	390	379	90	469
Total Generation Revenues net of purchased power and fuel expense	\$ 2,297	\$	\$ 2,297	\$ 2,407	\$	\$ 2,407

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

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a \$19 million and \$38 million increase to RNF for the amortization of intangible assets related to commodity contracts for the three months ended March 31, 2016 and 2015, respectively, unrealized mark-to-market gains of \$103 million and \$162 million for the three months ended March 31, 2016 and 2015, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

(c) Exelon corrected an error in the March 31, 2015 balances within Intersegment RNF and RNF from external customers for an understatement of \$4 million of Intersegment RNF for Reportable Segments for the three months ended March 31, 2015, an understatement of RNF from external customers for Reportable Segments of \$5 million for the three months ended March 31, 2015, an overstatement of \$4 million of Intersegment RNF for Other for the three months ended March 31, 2015, and an overstatement of RNF from external customers for Other of \$5 million for the three months ended March 31, 2015. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of \$9 million for the three months ended March 31, 2015. The error is not considered material to any prior period, and there is no net impact to Generation Total RNF for 2015.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Successor and Predecessor PHI:**

		Pepco	DPL	ACE	Other <sup>(b)</sup>	Intersegment Eliminations	PHI
<b>Operating revenues<sup>(a)</sup>:</b>							
March 24, 2016 to March 31, 2016	Successor						
Rate-regulated electric revenues		\$ 40	\$ 24	\$ 23	\$ 3	\$	\$ 90
Rate-regulated natural gas revenues			3				3
Shared service and other revenues					12		12
January 1, 2016 to March 23, 2016	Predecessor						
Rate-regulated electric revenues		\$ 511	\$ 279	\$ 268	\$ 42	\$ (4)	\$ 1,096
Rate-regulated natural gas revenues			56		1		57
Shared service and other revenues							
Three months ended March 31, 2015	Predecessor						
Rate-regulated electric revenues		\$ 545	\$ 335	\$ 334	\$ 58	\$ (4)	\$ 1,268
Rate-regulated natural gas revenues			86				86
Shared service and other revenues							
<b>Intersegment revenues:</b>							
March 24, 2016 to March 31, 2016	Successor	\$	\$	\$	\$ 12	\$	\$ 12
January 1, 2016 to March 23, 2016	Predecessor	1	2	1		(4)	
Three months ended March 31, 2015	Predecessor	1	2	1		(4)	
<b>Net income (loss):</b>							
March 24, 2016 to March 31, 2016	Successor	\$ (140)	\$ (98)	\$ (105)	\$ 22	\$ 12	\$ (309)
January 1, 2016 to March 23, 2016	Predecessor	32	26	5	(44)		19
Three months ended March 31, 2015	Predecessor	26	32	9	(14)		53
<b>Total assets:</b>							
March 31, 2016	Successor	\$ 6,877	\$ 3,959	\$ 3,393	\$ 11,077	\$ (4,374)	\$ 20,932
December 31, 2015	Predecessor	6,908	3,969	3,387	7,158	(5,238)	16,184

(a) Includes gross utility tax receipts from customers. The offsetting remittance of utility taxes to the governing bodies is recorded in expenses on the Registrants' Consolidated Statements of Operations and Comprehensive Income. See Note 19 - Supplemental Financial Information for total utility taxes for the three months ended March 31, 2016 and 2015.

(b) Other primarily includes PHI's corporate operations, shared service entities and other financing and investment activities. For the predecessor periods presented, Other includes the activity of PHI's unregulated businesses which were distributed to Exelon and Generation as a result of the PHI Merger.

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**Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations**

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

**Exelon Corporation**

**General**

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

*Generation*, whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).

*ComEd*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in northern Illinois, including the City of Chicago.

*PECO*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

*BGE*, whose business consists of the purchase and regulated retail sale of electricity and natural gas and the provision of electricity distribution and transmission and natural gas distribution services in central Maryland, including the City of Baltimore.

*Pepco*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission in the District of Columbia and major portions of Prince George's County and Montgomery County in Maryland.

*DPL*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services in northern Delaware.

*ACE*, whose business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services in southern New Jersey.

Exelon has twelve reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI's three utility reportable segments (Pepco, DPL and ACE). See Note 20 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon's corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon's consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd,

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PECO, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

**Table of Contents****Executive Overview**

**Financial Results.** The following table sets forth the consolidated financial results of Exelon for the three months ended March 31, 2016 compared to the same period in 2015. The 2016 financial results only include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through March 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended March 31, 2016						2015		Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI <sup>(b)</sup>	Other	Exelon	Exelon	Variance
<b>Operating revenues</b>	\$ 4,739	\$ 1,249	\$ 841	\$ 929	\$ 105	\$ (290)	\$ 7,573	\$ 8,830	\$ (1,257)
<b>Purchased power and fuel</b>	2,442	348	321	373	38	(268)	3,254	4,470	1,216
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	2,297	901	520	556	67	(22)	4,319	4,360	(41)
<b>Other operating expenses</b>									
Operating and maintenance	1,467	368	215	202	449	134	2,835	2,081	(754)
Depreciation and amortization	289	189	67	109	14	17	685	610	(75)
Taxes other than income	126	75	42	58	15	9	325	304	(21)
Total other operating expenses	1,882	632	324	369	478	160	3,845	2,995	(850)
<b>Gain on sales of assets</b>		5				4	9	1	8
<b>Operating income (loss)</b>	415	274	196	187	(411)	(178)	483	1,366	(883)
<b>Other income and (deductions)</b>									
Interest expense, net	(97)	(86)	(31)	(24)	(6)	(43)	(287)	(345)	58
Other, net	93	4	2	4	2	9	114	80	34
Total other income and (deductions)	(4)	(82)	(29)	(20)	(4)	(34)	(173)	(265)	92
<b>Income (loss) before income taxes</b>	411	192	167	167	(415)	(212)	310	1,101	(791)
<b>Income taxes</b>	151	77	43	66	(106)	(47)	184	363	179
<b>Equity in losses of unconsolidated affiliates</b>	(3)						(3)		3
<b>Net income (loss)</b>	257	115	124	101	(309)	(165)	123	738	(615)
Net (loss) income attributable to noncontrolling interests and preference stock dividends	(53)			3			(50)	45	95
<b>Net income (loss) attributable to common shareholders</b>	\$ 310	\$ 115	\$ 124	\$ 98	\$ (309)	\$ (165)	\$ 173	\$ 693	\$ (520)

(a) The Registrants evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate their operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b)

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As a result of the PHI Merger, PHI includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016, through March 31, 2016.

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* Exelon's net income attributable to common shareholders was \$173 million for the three months ended March 31, 2016 as compared to \$693 million for the three months ended March 31, 2015, and diluted earnings per average common share were \$0.19 for the three months ended March 31, 2016 as compared to \$0.80 for the three months ended March 31, 2015.

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Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by \$41 million for the three months ended March 31, 2016 as compared to the same period in 2015. The year-over-year decrease in operating revenue net of purchased power and fuel expense was primarily due to the following unfavorable factors:

Decrease of \$31 million at Generation primarily due to lower realized energy prices and higher oil inventory write downs in 2016 versus 2015, partially offset by nuclear refueling outage timing, fewer non-refueling outage days and increased capacity prices;

Decrease of \$59 million at Generation due to mark-to-market gains of \$103 million in 2016 from economic hedging activities as compared to gains of \$162 million in 2015;

Decrease of \$19 million at Generation related to amortization of contracts recorded at fair value associated with prior acquisitions; and

Decrease of \$27 million at PECO primarily due to less favorable weather conditions, partially offset by increased electric distribution rate revenue pursuant to the 2015 PAPUC authorized rate increase effective January 1, 2016.

The year over year decrease in operating revenue net of purchased power and fuel expense was partially offset by the following favorable factors:

Increase of \$43 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from increased capital investment;

Increase of \$7 million at BGE primarily due to an increase in transmission revenue resulting from increased capital investment and operating and maintenance expense; and

Increase of \$67 million in revenue net of purchased power and fuel due to the inclusion of PHI results for the period of March 24, 2016 to March 31, 2016.

Operating and maintenance expense increased by \$754 million for the three months ended March 31, 2016 as compared to the same period in 2015 primarily due to the following unfavorable factors:

Approval of the merger across all regulatory jurisdictions was conditioned on Exelon and PHI agreeing to certain commitments pursuant to which, upon acquisition close, Exelon recorded \$508 million of costs.

Increase in severance expense of \$52 million and \$17 million related to employee headcount reductions as a result of the closing of the PHI acquisition and the cost management program, respectively;

Long-lived asset impairments of Upstream assets at Generation of \$119 million; and

An increase in storm costs at BGE of \$17 million.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factors:

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Decrease of \$7 million due to a reduction in the number of nuclear refueling outage days at Generation, including Salem; and

Decrease of \$18 million in pension and non-pension post-retirement benefits resulting from the favorable impact of higher pension and OPEB discount rates in 2016.

Depreciation and amortization expense increased by \$75 million primarily as a result of increased depreciation expense for Generation and ComEd for ongoing capital expenditures, and increased nuclear decommissioning amortization at Generation.

Taxes other than income increased by \$21 million primarily due to increased payroll taxes and sales and use tax.

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Interest expense decreased by \$58 million primarily as a result of the absence of the forward-starting interest rate swaps in 2016.

Other, net increased by \$34 million primarily at Generation as a result of the change in realized and unrealized gains and losses on NDT funds and the absence of a \$26 million loss in 2015 on the termination of forward-starting interest rate swaps.

Exelon's effective income tax rates for the three months ended March 31, 2016 and 2015 were 59.4% and 33.0%, respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. As a result of the merger, Exelon recorded an after-tax charge of \$90 million during the three months ended March 31, 2016 as a result of assessment and remeasurement of certain federal and state PHI, Pepco, DPL and ACE uncertain tax positions.

For further detail regarding the financial results for the three months ended March 31, 2016, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

**Adjusted (non-GAAP) Operating Earnings.** Exelon's adjusted (non-GAAP) operating earnings for the three months ended March 31, 2016 were \$632 million, or \$0.68 per diluted share, compared with adjusted (non-GAAP) operating earnings of \$615 million, or \$0.71 per diluted share for the same period in 2015. In addition to net income attributable to common shareholders, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three months ended March 31, 2016 as compared to the same period in 2015. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended March 31,			
	2016		2015	
	Earnings per Diluted Share		Earnings per Diluted Share	
<b>(All amounts after tax)</b>				
Net Income Attributable to Common Shareholders	\$ 173	\$ 0.19	\$ 693	\$ 0.80
Mark-to-Market Impact of Economic Hedging Activities <sup>(a)</sup>	(64)	(0.07)	(100)	(0.11)
Unrealized Gains Related to NDT Fund Investments <sup>(b)</sup>	(31)	(0.03)	(24)	(0.03)
Merger and Integration Costs <sup>(c)</sup>	76	0.08	21	0.02
Merger Commitments <sup>(d)</sup>	394	0.42		
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps <sup>(e)</sup>			48	0.06
Long-Lived Asset Impairment <sup>(f)</sup>	71	0.07		
Amortization of Commodity Contract Intangibles <sup>(g)</sup>	(12)	(0.01)	(24)	(0.03)
Midwest Generation Bankruptcy Recoveries <sup>(h)</sup>			(6)	(0.01)
Cost Management Program <sup>(i)</sup>	14	0.02		
CENG Non-Controlling Interest <sup>(j)</sup>	11	0.01	7	0.01
<b>Adjusted (non-GAAP) Operating Earnings</b>	<b>\$ 632</b>	<b>\$ 0.68</b>	<b>\$ 615</b>	<b>\$ 0.71</b>



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- (a) Reflects the impact of net (gains) for the three months ended March 31, 2016 and 2015 (net of taxes of \$39 million and \$63 million, respectively), on Generation's economic hedging activities. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.
- (b) Reflects the impact of net unrealized (gains) for the three months ended March 31, 2016 and 2015 (net of taxes of \$35 million and \$26 million, respectively), on Generation's NDT fund investments for Non-Regulatory Agreement Units. See Note 12 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.
- (c) Reflects certain costs incurred for the three months ended March 31, 2016 and 2015 (net of taxes of \$26 million and \$13 million, respectively), including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, and certain pre-acquisition contingencies, and the PHI acquisition. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to merger and acquisition costs.
- (d) Reflects the costs incurred as part of the settlement orders approving the PHI acquisition (net of taxes of \$114 million). See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to PHI Merger commitments.
- (e) For 2015, reflects the impact of net losses on forward-starting interest rate swaps at Exelon Corporate related to financing of the PHI acquisition (net of taxes of \$31 million).
- (f) Reflects the impairment of Upstream assets at Generation in 2016 (net of taxes of \$49 million).
- (g) Reflects the non-cash impact for the three months ended March 31, 2016 and 2015 (net of taxes of \$7 million and \$14 million, respectively), of the amortization of intangible assets, net, related to commodity contracts recorded at fair value for the Integrys acquisition.
- (h) For 2015, reflects a benefit related to the favorable settlement of a long term railcar lease agreement pursuant to the Midwest Generation bankruptcy (net of taxes of \$4 million).
- (i) For 2016, reflects the severance expense and reorganization costs related to a cost management program (net of taxes of \$9 million).
- (j) Represents Generation's non-controlling interest related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments.

**Merger and Acquisition Costs**

On March 23, 2016, the Exelon and PHI Merger was completed. On the merger date, PHI shareholders received \$27.25 of cash in exchange for each share of PHI common stock. The resulting company will retain the Exelon name and be headquartered in Chicago.

As a result of the PHI Merger, Exelon has incurred and will continue to incur costs associated with evaluating, structuring and executing the PHI Merger transaction itself, meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former PHI businesses into Exelon.

The table below presents the one-time pre-tax charges recognized upon closing of the PHI Merger included in the Registrant's respective Consolidated Statement of Operations and Comprehensive Income.

	Three Months Ended March 31, 2016							Successor March 24, 2016 to March 31, 2016 PHI	
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	
Merger commitments	\$ 508	\$ 3	\$	\$	\$	\$ 139	\$ 104	\$ 120	\$ 363
Employee related charges <sup>(a)</sup>	71	12	1	1	1	27	16	13	56
Changes in accounting and tax related policies and estimates <sup>(b)</sup>						25	15	5	
Total	\$ 579	\$ 15	\$ 1	\$ 1	\$ 1	\$ 191	\$ 135	\$ 138	\$ 419

(a)

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- Primarily relates to severance, see Note 14 Severance of the Combined Notes to Consolidated Financial Statements for additional information.
- (b) Primarily relates to income taxes, see Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

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In addition to the one-time PHI Merger charges discussed above, for the three months ended March 31, 2016, expense has been recognized for merger, integration and acquisition costs for the PHI Merger and for the three months ended March 31, 2015, expense has been recognized primarily for merger, integration and acquisition costs for the PHI Merger, Integrys acquisition and CENG integration as follows:

Merger, Integration and Acquisition Costs:	Pre-tax Expense									Successor March 24, 2016 to March 31, 2016
	Three Months Ended March 31, 2016									
	Exelon <sup>(a)</sup>	Generation <sup>(a)</sup>	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI <sup>(a)</sup>	
Transaction <sup>(c)</sup>	\$ 35	\$	\$	\$	\$	\$	\$	\$	\$	\$
Employee-Related <sup>(d)</sup>	71	12	1	1	1	27	16	13		56
Other <sup>(e)</sup>	(4)	4	(9)	1	1					
Total	\$ 102	\$ 16	\$ (8)	\$ 2	\$ 2	\$ 27	\$ 16	\$ 13		\$ 56

Merger and Integration Costs:	Pre-tax Expense				
	Three Months Ended March 31, 2015				
	Generation	ComEd	PECO	BGE	Exelon
Financing <sup>(b)</sup>	\$	\$	\$	\$	\$ 89
Transaction <sup>(c)</sup>					6
Employee-Related <sup>(d)</sup>	4				4
Other <sup>(e)</sup>	7	3	1	1	13
Total	\$ 11	\$ 3	\$ 1	\$ 1	\$ 112

(a) For Exelon, Generation and PHI, includes the operations of the acquired businesses from March 24, 2016 through March 31, 2016.

(b) Reflects costs incurred at Exelon related to the financing of the PHI Merger, including upfront credit facility fees.

(c) External, third party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of transactions.

(d) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

(e) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the three months ended March 31, 2016, also includes professional fees primarily related to integration for the PHI acquisition.

As of March 31, 2016, Exelon expects to incur total PHI acquisition and integration related costs of approximately \$700 million, excluding merger commitments. Of this amount, including 2014 and through March 31, 2016, Exelon has incurred approximately \$346 million. Included in this amount are costs to fund the merger of which \$76 million has been expensed, \$56 million has been paid and recorded as deferred debt issuance costs and \$60 million has been incurred and charged to common stock. The remaining costs will be primarily within Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income and will also include approximately \$60 million for integration costs expected to be capitalized to Property, plant and equipment. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for further information regarding the PHI acquisition.

**Exelon's Strategy and Outlook for the remainder of 2016 and Beyond**

Exelon's value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon's regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

Exelon's utilities provide a foundation for stable earnings, which translates to a stable currency in our stock.

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Generation s competitive businesses provide free cash flow to invest primarily into the utilities and in long-term, contracted assets. Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Exelon utilities only invest in rate base where it provides a net benefit to customers and the community by improving reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments prudently and at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Additionally, the Utility Registrants anticipate making significant future investments in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation s competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. Generation s electricity generation strategy is to pursue opportunities that provide generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation s customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon s financial priorities are to maintain investment grade credit metrics at each of the Registrants to maintain optimal capital structure and to return value to Exelon s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon s Board of Directors approved a revised dividend policy. The approved policy raises our dividend 2.5% each year for the next three years, beginning with the June 2016 dividend.

Various market, financial, and other factors could affect the Registrants success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS of the Exelon 2015 Form 10-K for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon s financial strategy. Through a recent focused cost management program, the company has committed to reducing operation and maintenance expenses and capital costs by \$350 million, of which approximately 35% of run-rate savings are expected to be achieved by the end of 2016 and fully realized in 2018. Savings are expected to be allocated approximately 75%, 14%, 6% and 6% to Generation, ComEd, PECO and BGE, respectively. Exelon anticipates the earnings per share savings impact on EPS will be within \$0.13 to \$0.18 from 2018 forward.

***Implications of Potential Early Plant Retirements***

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation s nuclear plants. Factors that will continue to affect the economic value of Generation s nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions in New York and Illinois such as the recently proposed Zero Emission Standard element of the Next Generation Energy Plan (NGEP) or Low Carbon Portfolio Standard (LCPS) legislation in Illinois and Clean Energy Standard (CES) in New York, the impact of final rules from the EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules.

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In 2015, 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 auction to be 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. The results of the 2019-2020 PJM capacity auction will be available on May 24, 2016.

On May 6, 2016 Exelon and Generation announced intentions to shut down the Clinton nuclear plant on June 1, 2017 and Quad Cities nuclear plant on June 1, 2018 if Illinois does not pass adequate legislation by May 31, 2016 and if Quad Cities does not clear the 2019-2020 PJM capacity auction. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. The approved RSSA requires Ginna to continue operating through the RSSA term expiring in March 2017. There remains an increased risk that, for economic reasons, Ginna could be retired before the end of its operating license period in 2029 if an adequate regulatory or legislative solution is not adopted in New York. Refer to Note 5 Regulatory Matters for additional discussion on the Ginna RSSA.

In response to a decision to early retire one or more other nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by a number of items including, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, contract termination fees, accelerated amortization of plant specific nuclear fuel costs, employee-related costs (i.e. severance, relocation, retention, etc.), accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of nuclear decommissioning trust funds. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown.

The following table provides the balance sheet amounts as of March 31, 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 their current economic valuations and other factors.

<i>(in millions)</i>	Quad Cities	Clinton	Ginna	Total
<b>Asset Balances</b>				
Materials and supplies inventory	\$ 47	\$ 58	\$ 30	\$ 135
Nuclear fuel inventory, net	213	95	54	362
Completed plant, net	1,014	574	127	1,715
Construction work in progress	28	11	11	50
<b>Liability Balances</b>				
Asset retirement obligation	(706)	(407)	(651)	(1,764)
NRC License Renewal Term	2032	2046 <sup>(a)</sup>	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

The precise timing of the retirement date, and resulting financial statement impact, may be affected by a number of factors, including the 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 and just prior to its next scheduled nuclear refueling outage date in that year.

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the

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end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then Generation would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available.

As of March 31, 2016, all three of Generation's plants at the highest risk of early retirement (Quad Cities, Clinton, and Ginna) pass the NRC minimum funding test based on their current license lives. See Note 12 Nuclear Decommissioning for additional information on NRC minimum funding requirements. However, in the event of an early retirement just before their next individual refueling outages, it is estimated that Clinton and Ginna would no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. Quad Cities would also be at risk. A shortfall could require Exelon to post parental guarantees for Generation's obligations. However, the amounts of any required guarantees will ultimately depend on the decommissioning approach adopted at each site (i.e., DECON, Delayed DECON and SAFSTOR), the associated level of costs, and the decommissioning trust fund investment performance going forward. Considering the three alternative decommissioning approaches available to Generation for each site, the most costly estimates currently anticipated could require parental guarantees of up to \$385 million and \$260 million for Clinton and Ginna, respectively, in order for each site to access its NDT fund for radiological decommissioning costs. Although Quad Cities is better positioned than the other two plants to avoid the need for a parental guarantee, if required, it could be up to \$65 million in order for the site to access its NDT fund for radiological decommissioning costs.

In addition, upon issuance of any required financial guarantees, while all three sites would be able to utilize their respective decommissioning trust funds for radiological decommissioning costs which represents the majority of the total expected decommissioning costs, the NRC must approve an additional exemption in order for Generation to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by Generation. Accordingly, based on current projections, it is expected that some portion of the spent fuel management and/or site restoration costs would need to be funded through supplemental cash from Generation. While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under DOE reimbursement agreements or future litigation, across the three alternative decommissioning approaches available to Generation, for the next 10 years, Clinton and Ginna could incur spent fuel management and site restoration costs of up to \$160 million and \$115 million, net of taxes, respectively. The costs associated with Ginna would be shared by the plant co-owners at their respective ownership percentages. Quad Cities is better positioned to pass the test than the other two plants. Although considered unlikely, if Quad Cities fails the exemption test, at its ownership percentage Generation could be required to pay for spent fuel management costs of up to \$180 million, net of taxes.

***Power Markets***

***Price of Fuels.*** The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

***Capacity Market Changes in PJM.*** In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. As a result, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally sought to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to

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improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Generation participated actively in PJM's stakeholder process through which PJM developed the proposal and also actively participated in the FERC proceeding including filing comments. On June 9, 2015, FERC approved PJM's filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. As a result of this and several related orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015).

***MISO Capacity Market Results.*** On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to \$150 per MW per day beginning in June 2015, an increase from the prior pricing of \$16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation's ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon's and Generation's consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc. and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants, other than Exelon or Generation, be investigated.

On October 1, 2015, the FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, the FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are "not just and reasonable" on a prospective basis. The FERC ordered that certain rules must be changed for the next auction scheduled for April 2016 that will set capacity prices beginning June 1, 2016. In response to this order, MISO must file certain rule changes with the FERC within 30 days and certain other changes within 90 days. The FERC continues to conduct its non-public investigation to determine if the April 2015 auction results were manipulated and, if so, whether refunds are appropriate. The FERC did establish May 28, 2015, the day the first complaint was filed, as the date from which refunds (if ordered) would be calculated, and it also made clear that the findings in the December 31, 2015 order do not prejudice the investigation or related proceedings. On March 18, 2016, the FERC denied rehearing of its December 31, 2015 order in this matter. On April 14, 2016, the MISO released the results of the 2016/2017 capacity auction; the zone 4 region in downstate Illinois cleared the auction at a rate of \$72 per MW per day. Clinton nuclear plant, which operates in the zone 4 region, cleared the auction and is committed to operate through May 31, 2017. See Note 7 Implications of Potential Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

MISO has acknowledged the need for capacity market design changes in the zone 4 region and stated that reforms to its capacity market process may be required to drive future investment and that it plans to engage stakeholders to consider such reforms. The FERC has also encouraged such efforts, and Exelon has been working with MISO and its stakeholders on such market changes.

***Subsidized Generation.*** The rate of expansion of subsidized generation, including low-carbon generation such as wind and solar energy, in the markets in which Generation's output is sold can negatively impact wholesale power prices, and in turn, Generation's results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices.



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For example, Exelon and others challenged the constitutionality and other aspects of New Jersey legislation aimed at suppressing capacity market prices in federal court. See Note 5 Regulatory Matters for additional information on state specific actions taken in Maryland and New Jersey. Similar actions taken by the MDPSC were also challenged in federal court in an action to which Exelon was not a party. The federal trial courts in both the New Jersey and Maryland actions effectively invalidated the actions taken by the New Jersey legislature and the MDPSC, respectively. Those decisions were upheld by the U.S. Court of Appeals. On April 19, 2016, the U.S. Supreme Court unanimously affirmed the Fourth Circuit decision holding that the MDPSC's required contracts are illegal and unenforceable. On April 25, 2016, the U.S. Supreme Court denied certiorari concerning the Third Circuit decision. This denial of certiorari leaves the Third Circuit decision in place, with the same outcome as the Fourth Circuit decision.

Nonetheless, Exelon believes that these projects may have already artificially suppressed capacity prices in PJM in these auctions. While the Supreme Court decision is a positive development, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows.

One such state is Ohio, where state-regulated utility companies FirstEnergy Ohio (FE) and AEP Ohio (AEP) initiated actions at the Public Utilities Commission of Ohio (PUCO) to obtain approval for Riders that effectively allow these two companies to pass through to all customers in their service territories the differences between their costs and market revenues on PPAs entered into between the utility and its merchant generation affiliate. Collectively more than 6,000MW of primarily coal-fired generation owned by FE and AEP's affiliates seek ratepayer guaranteed subsidies via the proposed Riders. Thus, the Riders are similar to the CfDs described above (except that the PPA Riders in Ohio would apply to certain existing generation facilities whereas the CfDs applied to new generation facilities). While AEP and FE initially filed for these Riders in 2013 and 2014, respectively, it was not until late 2015 that the proposals obtained meaningful traction when PUCO staff entered into a settlement and stipulation with the Ohio utilities supporting the proposals and recommending that the PUCO approve the Riders. Exelon is a participant in these proceedings. On March 31, 2016, PUCO issued separate orders generally approving each of the FE and AEP arrangements. In addition, separate complaints have been filed at the FERC pursuing federal causes of action (i) seeking to impose affiliate self-dealing requirements on the PPAs and (ii) seeking to impose a MOPR on the resources supporting the PPAs. On April 27, 2016, the FERC issued orders on the affiliate matter rescinding certain affiliate waivers previously granted to AEP and FE and requiring each to demonstrate that the PPAs (prior to transacting under them) were entered into on an arms-length basis and do not reflect any affiliate preference. We do not expect such a showing could be made prior to PJM's capacity auction that ends on May 24, 2016. Thus, it is unlikely the PPAs will impact the results of the upcoming auction. Nonetheless, further action by AEP and FE related to the PPAs is possible. In addition, the outcome of the MOPR complaint and its impact, if any, on Generation is not yet clear as it is too early in the proceeding to predict its outcome. Finally, Dayton Power and Light filed at PUCO seeking approval of similar arrangements.

Exelon has opposed the proposals in Ohio, continues to monitor developments in Maryland and New Jersey and participates in stakeholder and other processes to ensure that only appropriate state subsidies are developed. Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/or consumers to subsidize or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid.

**Energy Demand.** Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for BGE and PECO and a decrease in projected load for electricity for ComEd, Pepco, DPL and ACE. BGE, PECO, ComEd, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by 0.1%, 0.4%, (0.2)%, (0.7)%, (0.3)% and (2.2)% respectively, in 2016 compared to 2015.

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***Retail Competition.*** Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. We expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

### **Strategic Policy Alignment**

Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon's Board of Directors declared the first quarter 2016 dividends of \$0.31 per share each on Exelon's common stock. The first quarter 2016 dividend was paid on March 10, 2016.

Exelon's Board of Directors declared the second quarter 2016 dividends of \$0.318 per share each on Exelon's common stock and is payable on June 10, 2016. The dividend increased from the first quarter amount to reflect the Board's decision to raise Exelon's dividend 2.5% each year for the next three years, beginning with the June 2016 dividend.

All future quarterly dividends require approval by Exelon's Board of Directors.

### **Hedging Strategy**

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2016 and 2017. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of March 31, 2016, the percentage of expected generation hedged for the major reportable segments is 96%-99%, 69%-72% and 37%-40% 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, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2016 through 2020 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrate can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

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

### **Growth Opportunities**

Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas and offering sustainable returns.

### **Regulated Energy Businesses**

The completed merger with PHI provides an opportunity to accelerate Exelon's regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately \$25 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately \$11 billion by the end of 2020. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made prudently and at the lowest reasonable cost to customers.

See Note 5 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives and infrastructure development and enhancement programs.

### **Competitive Energy Businesses**

Generation continually assesses the optimal structure and composition of our generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to prioritize investments in long-term contracted generation across multiple technologies and identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, while identifying emerging technologies where strategic investments provide the option for significant future growth or influence in market development. As of March 31, 2016, Generation has currently approved plans to invest a total of approximately \$2 billion in 2016 through 2018 on capital growth projects (primarily new plant construction and distributed generation).

### **Liquidity**

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of \$9.5 billion. Generation also has bilateral credit facilities with aggregate maximum availability of \$425 million. See Liquidity and Capital Resources – Credit Matters – Exelon Credit Facilities below.

**Exposure to Worldwide Financial Markets.** Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of March 31, 2016, approximately 22%, or

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\$2.2 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include \$9.9 billion in aggregate total commitments of which \$8.3 billion was available as of March 31, 2016, due to outstanding letters of credit. There were no borrowings under the Registrants' credit facilities as of March 31, 2016. See Liquidity and Capital Resources - Credit Matters - Exelon Credit Facilities for additional information.

**Tax Matters**

See Note 11 - Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

***Environmental Legislative and Regulatory Developments.***

Exelon is actively involved in the EPA's development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for electric generating units, as set forth in the discussion below. These regulations have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Retirements of coal-fired power plants will continue as additional EPA regulations take effect, and as air quality standards are updated and further restrict emissions. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the EPA's rulemaking efforts, and it is uncertain whether any of these bills will become law.

***Air Quality.*** In recent years, the EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act applicable to electric generating units. These regulations have resulted in more stringent emissions limits on fossil-fuel electric generating stations as states implement their compliance plans.

***National Ambient Air Quality Standards (NAAQS).*** The EPA continues to review and update its NAAQS for conventional air pollutants relating to ground-level ozone and emissions of particulate matter, SO<sub>2</sub> and NO<sub>x</sub>. Following five years of litigation, the EPA is finalizing the Cross State Air Pollution Rule that requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states.

***Mercury and Air Toxics Standard Rule (MATS).*** On December 16, 2011, the EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals, and to make capital investments in pollution control equipment and incur higher operating expenses. The initial compliance deadline to meet the new standards was April 16, 2015; however, facilities may have been granted an additional one or two year extension in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. In April 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety. On appeal, the U.S. Supreme Court decided in June 2015 that the EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The U.S. Supreme Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court to take further action consistent with the U.S. Supreme Court's opinion on this single issue. As such, the MATS rule remains in effect. Exelon will continue to participate in the remanded proceedings before the D.C. Circuit Court as an intervenor in support of the rule.

***Climate Change.*** Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the

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economy with the urgent need to reduce national GHG emissions. In the absence of federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ( UNFCCC of Convention ). See ITEM 1. BUSINESS, Global Climate Change of the Exelon 2015 Form 10-K for further discussion.

**Water Quality.** Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation s power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. Those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. See ITEM 1. BUSINESS, Water Quality of the Exelon 2015 Form 10-K for further discussion.

**Solid and Hazardous Waste.** In October 2015, the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants became effective. The rule classifies CCR as non-hazardous waste under RCRA. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon s and Generation s financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

### **Other Regulatory and Legislative Actions**

**Illinois Low Carbon Portfolio Standard (Exelon, Generation and ComEd).** In March 2015, the Low Carbon Portfolio Standard (LCPS) was introduced in the Illinois General Assembly. The legislation would require ComEd and Ameren to purchase low carbon energy credits to match 70 percent of the electricity used on the distribution system. The LCPS is a technology-neutral solution, so all generators of zero or low carbon energy would be able to compete in the procurement process, including wind, solar, hydro, clean coal and nuclear. Costs associated with purchasing the low carbon energy credits would be collected from customers. The LCPS proposal includes consumer protections such as a price cap that would limit the impact to a 2.015% increase based off 2009 monthly bills, or about \$2 per month for the average residential electricity customer, similar to the cost cap protection under other clean energy programs in Illinois. The legislation also includes a separate customer rebate provision that would provide a direct bill credit to customers in the event wholesale prices exceed a specified level. The proposed legislation remains pending along with two other major energy bills. Exelon and Generation continue to work with stakeholders on a comprehensive energy package.

**Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greener Illinois (Exelon and ComEd).** In March 2015, legislation was introduced in the Illinois General Assembly that would (1) build on ComEd s investment in the Smart Grid to reinforce the resiliency and security of the electrical grid to withstand unexpected challenges, (2) expand energy efficiency programs to reduce energy waste and increase customer savings, (3) further integrate clean renewable energy onto the power system, and (4) introduce a new demand-based rate design for residential customers that would allow for a more equitable sharing of smart grid costs among customers. The legislation also provides for additional funding for customer assistance programs for low-income customers. The proposed legislation is pending and ComEd continues to work with stakeholders.

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**Next Generation Energy Plan (Exelon, Generation and ComEd).** On May 5, 2016, the Next Generation Energy Plan was introduced in the Illinois General Assembly. The legislation contains significant parts of the previously introduced Illinois Low Carbon Portfolio Standard and Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greater Illinois, along with new elements. The legislation includes (1) a Zero Emission Standard providing compensation for at-risk nuclear plants that demonstrate their revenues are insufficient to cover their costs, (2) \$1 billion of funding for low-income assistance, including \$650 million for energy efficiency programs, \$250 million in Renewable Energy Resource Funds, \$50 million in Percentage of Income Payment Plan funding and utility bill assistance, and \$50 million in ComEd CARE, (3) \$140 million in new funding for solar development and a new solar rebate to incent solar generation, (4) additional investment at ComEd to enhance reliability and security of the power grid, (5) an expansion of the Renewable Portfolio Standard, and (6) a 50% reduction in the fixed customer charge for energy delivery creating more equitable rates across customers. The proposed legislation is pending and Exelon, Generation, and ComEd continue to work with stakeholders. See Note 7 Implications of Potential Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

**Distribution Formula Rate (Exelon and ComEd).** On April 13, 2016, ComEd filed its annual distribution formula rate with the ICC, requesting 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 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. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to distribution formula updates.

**2016 Maryland Electric Distribution Base 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 annual service revenues for electric delivery. Pepco requested ROE for the electric distribution rate case of 10.6%. Any adjustments to rates approved by the MDPSC are expected to take effect in 2016. In addition to the proposed \$127 million rate increase, Pepco is proposing to continue its Grid Resiliency Charge initially approved in July 2013 in connection with Pepco's electric distribution rate case filed in November 2012. In connection with the Grid Resiliency Charge, 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 increase the MDPSC will approve or if it will approve Pepco's Grid Resiliency Charge proposal.

**2016 Electric Distribution Base Rates (Exelon, PHI and ACE).** On March 22, 2016, ACE filed an application with the NJBPU requesting an increase of \$84 million to its annual service revenues for electric delivery, based on a requested ROE of 10.6%. In addition to the request for base rate relief, ACE has also included a request that the NJBPU approve ACE's five-year grid resiliency initiative known as PowerAhead. As proposed, PowerAhead includes \$176 million of 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. A decision is expected in the first half of 2017. ACE cannot predict how much of the requested increase the NJBPU will approve or if it will approve ACE's PowerAhead initiative.

**2015 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE).** On November 6, 2015, and as amended in the first quarter of 2016, BGE filed for electric and gas base rate increases with the MDPSC, ultimately requesting an increase of \$118 million and \$79 million respectively, of which \$104 million and \$37 million, respectively, is related to recovery of smart grid initiative costs. BGE requested a ROE for the electric and gas distribution rate case of 10.6% and 10.5% respectively. The new electric and gas base rates are expected to take effect in June 2016. BGE is also proposing to recover an annual increase of approximately \$30 million for Baltimore City conduit lease fees through a surcharge. BGE cannot predict how much of the requested increase the MDPSC will approve or if it will approve BGE's request for a conduit fee surcharge.

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**Transmission Formula Rate (Exelon, ComEd and BGE).** On April 13, 2016, ComEd filed its annual transmission formula rate update with the FERC, reflecting an increased revenue requirement of \$94 million, including an increase of \$90 million for the initial revenue requirement for 2016 and an increase of \$4 million related to the annual reconciliation for 2015. The filing establishes the revenue requirement used to set rates that will take effect in June 2016, subject to review by the FERC and other parties, which is due by October 2016. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to transmission formula update.

On April 27, 2016, BGE filed its annual transmission formula rate update based upon the FERC approved formula with the FERC. The filing establishes the revenue requirement used to set rates that will take effect in June 2016, subject to review by the FERC and other parties, which is due by third quarter 2016. BGE's 2016 annual update includes a total increase to the revenue requirement of \$15 million, reflecting an increase of \$12 million for the initial revenue requirement and a decrease of \$3 million related to the annual reconciliation. This increase excludes the \$13 million increase in revenue requirement associated with dedicated facilities charges. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.09%, inclusive of an allowed ROE of 10.50% a decrease from the 8.46% average debt and equity return previously authorized.

**FERC Transmission Complaint (Exelon, BGE, PHI, Pepco, DPL and ACE).** In February 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE, Pepco, DPL and ACE relating to their respective transmission formula rates. BGE's formula rate included a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (and certain additional incentive base points on certain projects). Pepco's, DPL's and ACE's formula rates included, for facilities placed into service after January 1, 2006, a base ROE of 11.3%, and for facilities placed into service prior to January 1, 2006, a base ROE of 10.8% and a 50 basis point incentive for participating in PJM. The parties sought a reduction in the base return on equity to 8.7% and changes to the formula rate process. Under FERC rules, any revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint.

On August 21, 2014, FERC issued an order in the BGE's, Pepco's, DPL's and ACE's proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013.

On February 23, 2016, FERC approved the settlement filed by the parties on November 6, 2015, covering the ROE issues raised in the complaints. The settlement provides for a 10% base ROE, effective March 8, 2016, which will be augmented by the PJM incentive adder of 50 basis points, and refunds to BGE, Pepco, DPL and ACE customers of \$13.7 million, \$14.2 million, \$11.9 million and \$9.5 million, respectively. The settlement also prohibits any settling party from filing to change the base ROE or any incentives prior to June 1, 2018. The date for filing a request for rehearing has expired without any such requests having been filed. Accordingly, the order is not eligible for appeal and the matter is considered closed. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

**Conduit Lease with City of Baltimore (Exelon and BGE).** On September 23, 2015, the Baltimore City Board of Estimates approved an increase in rental fees for access to the Baltimore City conduit system to be effective November 1, 2015, which is expected to result in an increase to Operating and maintenance expense of approximately \$25 million in 2016 subject to an annual increase based on the Consumer Price Index. On October 16, 2015, BGE filed a lawsuit against the City in the Circuit Court for Baltimore City to protect its customers from any improper use by the City of the conduit fee revenues and to place constraints on the City's ability to set the conduit fee in the future.

Among the relief sought by BGE was a preliminary injunction preventing the City from enforcing its substantial increase in the conduit fee rate during the course of the litigation. A hearing was held in the Circuit

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Court for Baltimore County on December 15, 2015. While BGE's motion for preliminary injunction was denied, the Court's decision was premised upon several important concessions or acknowledgments made by the City in its written papers and at the hearing. Most importantly, the City conceded that it can charge BGE only for the actual costs of conduit maintenance and that a true-up process is required to the extent that the City fails to spend the amount collected for conduit maintenance.

As part of its electric and gas distribution rate case filed on November 6, 2015, and as amended in the first quarter of 2016, BGE is proposing to recover the annual increase in conduit fees effective November 1, 2015 of approximately \$30 million through a surcharge. BGE cannot predict if the MDPSC will approve BGE's request for a conduit fee surcharge.

**Employees**

During the first quarter of 2016, the collective bargaining agreement (CBA) between ComEd and IBEW Local 15, which represents the ComEd's System Services Group, was further extended to May 31, 2016. In addition, Exelon added 5,174 total employees from its merger with PHI and its subsidiaries, of which 2,725 are covered by CBAs. PHI's utility subsidiaries are parties to five CBAs with four local unions. All of the CBAs were renegotiated in 2014, and were extended through various dates ranging from October 2018 through June 2020.

**Critical Accounting Policies and Estimates**

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - CRITICAL ACCOUNTING POLICIES AND ESTIMATES in Exelon's, Generation's, ComEd's, PECO's and BGE's combined 2015 Form 10-K and PHI's, Pepco's, DPL's and ACE's 2015 combined Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, goodwill, purchase accounting, unamortized energy assets and liabilities, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies, revenue recognition, and allowance for uncollectible accounts. At March 31, 2016, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2015.

**Results of Operations****Net Income Attributable to Common Shareholders by Registrant**

	Three Months Ended March 31,		Favorable (Unfavorable)
	2016 <sup>(a)</sup>	2015	Variance
Exelon	\$ 173	\$ 693	\$ (520)
Generation	310	443	(133)
ComEd	115	90	25
PECO	124	139	(15)
BGE	98	106	(8)
Pepco	(108)	26	(134)
DPL	(72)	32	(104)
ACE	(100)	9	(109)

(a) For Pepco, DPL and ACE, reflects that Registrant's operations for the three months ended March 31, 2016. For Exelon and Generation, includes the operations of the PHI acquired businesses for the period of March 24, 2016, through March 31, 2016.



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	<i>Successor</i>	<i>Predecessor</i>	
	<b>March 24, 2016 to March 31, 2016</b>	<b>January 1, 2016 to March 23, 2016</b>	<b>Three Months Ended March 31, 2015</b>
PHI	\$ (309)	\$ 19	\$ 53
<i>Results of Operations Generation</i>			

	<b>Three Months Ended March 31,</b>		<b>Favorable (Unfavorable)</b>
	<b>2016</b>	<b>2015</b>	<b>Variance</b>
<b>Operating revenues</b>	\$ 4,739	\$ 5,840	\$ (1,101)
<b>Purchased power and fuel expense</b>	2,442	3,433	991
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	2,297	2,407	(110)
<b>Other operating expenses</b>			
Operating and maintenance	1,467	1,311	(156)
Depreciation and amortization	289	254	(35)
Taxes other than income	126	122	(4)
Total other operating expenses	1,882	1,687	(195)
<b>Loss on sales of assets</b>		(1)	1
<b>Operating income</b>	415	719	(304)
<b>Other income and (deductions)</b>			
Interest expense	(97)	(102)	5
Other, net	93	94	(1)
Total other income and (deductions)	(4)	(8)	4
<b>Income before income taxes</b>	411	711	(300)
<b>Income taxes</b>	151	226	75
<b>Equity in losses of unconsolidated affiliates</b>	(3)		3
<b>Net income</b>	257	485	(228)
Net (loss) income attributable to noncontrolling interests	(53)	42	95
<b>Net income attributable to membership interest</b>	\$ 310	\$ 443	\$ (133)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

**Net Income Attributable to Membership Interest**

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* Generation's net income attributable to membership interest for the three months ended March 31, 2016 decreased compared to the same period in 2015, primarily due to lower revenue net of purchased power and fuel expense, higher operating and maintenance expense and higher depreciation and amortization expense. The decrease

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in revenue net of purchased power and fuel expense primarily relates to the lower realized energy prices, lower mark-to-market gains in 2016 compared to 2015, decrease in amortization of contracts recorded at fair value associated with prior acquisitions, and higher oil inventory write downs in 2016 versus 2015, partially offset by nuclear refueling outage timing, fewer non-refueling outage days and increased capacity prices. The increase in operating

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and maintenance expense is primarily related to Upstream asset impairment in 2016. The increase in depreciation and amortization expense is primarily related to increased nuclear decommissioning amortization and ongoing capital expenditures in 2016.

### *Revenue Net of Purchased Power and Fuel Expense*

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

Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the United States footprint of MISO, excluding MISO's Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.

New York represents operations within ISO-NY, which covers the state of New York in its entirety.

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.

### Other Power Regions:

South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.

Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; and other miscellaneous revenues.

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Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs

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include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the three months ended March 31, 2016 and 2015, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended		Variance	% Change
	March 31,			
	2016	2015		
Mid-Atlantic <sup>(a)</sup>	\$ 841	\$ 787	\$ 54	6.9%
Midwest <sup>(b)</sup>	718	703	15	2.1%
New England	81	158	(77)	(48.7)%
New York	130	189	(59)	(31.2)%
ERCOT	61	55	6	10.9%
Other Power Regions	76	46	30	65.2%
<b>Total electric revenue net of purchased power and fuel expense</b>	<b>1,907</b>	<b>1,938</b>	<b>(31)</b>	<b>(1.6)%</b>
Proprietary Trading	3	4	(1)	(25.0)%
Mark-to-market gains (losses)	103	162	(59)	(36.4)%
Other <sup>(c)</sup>	284	303	(19)	(6.3)%
<b>Total revenue net of purchased power and fuel expense</b>	<b>\$ 2,297</b>	<b>\$ 2,407</b>	<b>\$ (110)</b>	<b>(4.6)%</b>

- (a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. As a result of the PHI Merger, for the Successor period of March 24, 2016 to March 31, 2016, results of transactions with Pepco, DPL and ACE are included in the Mid-Atlantic region.
- (b) Results of transactions with ComEd are included in the Midwest region.
- (c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of \$19 million and \$38 million increase to revenue net of purchased power and fuel expense for the three months ended March 31, 2016 and 2015, respectively.

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Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended March 31,		Variance	% Change
	2016	2015		
<b>Nuclear generation</b>				
Mid-Atlantic <sup>(a)</sup>	16,208	15,718	490	3.1%
Midwest	23,662	22,427	1,235	5.5%
New York <sup>(a)</sup>	4,932	4,512	420	9.3%
<b>Total Nuclear Generation</b>	<b>44,802</b>	<b>42,657</b>	<b>2,145</b>	<b>5.0%</b>
<b>Fossil and Renewables</b>				
Mid-Atlantic	898	559	339	60.6%
Midwest	449	432	17	3.9%
New England	1,924	600	1,324	n.m.
New York	1	1		%
ERCOT	1,376	1,422	(46)	(3.2)%
Other Power Regions	2,147	1,973	174	8.8%
<b>Total Fossil and Renewables</b>	<b>6,795</b>	<b>4,987</b>	<b>1,808</b>	<b>36.3%</b>
<b>Purchased Power</b>				
Mid-Atlantic	3,755	1,824	1,931	105.9%
Midwest	706	589	117	19.9%
New England	4,155	6,408	(2,253)	(35.2)%
ERCOT	2,294	2,244	50	2.2%
Other Power Regions	2,600	3,758	(1,158)	(30.8)%
<b>Total Purchased Power</b>	<b>13,510</b>	<b>14,823</b>	<b>(1,313)</b>	<b>(8.9)%</b>
<b>Total Supply/Sales by Region<sup>(b)</sup></b>				
Mid-Atlantic <sup>(c)</sup>	20,861	18,101	2,760	15.2%
Midwest <sup>(c)</sup>	24,817	23,448	1,369	5.8%
New England	6,079	7,008	(929)	(13.3)%
New York	4,933	4,513	420	9.3%
ERCOT	3,670	3,666	4	0.1%
Other Power Regions	4,747	5,731	(984)	(17.2)%
<b>Total Supply/Sales by Region</b>	<b>65,107</b>	<b>62,467</b>	<b>2,640</b>	<b>4.2%</b>

(a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG).

(b) Excludes physical proprietary trading volumes of 1,220 GWh and 1,808 GWh for the three months ended March 31, 2016 and 2015, respectively.

(c) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region. As a result of the merger, for the Successor period of March 24, 2016 to March 31, 2016, includes affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region.

*Mid-Atlantic*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$54 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects nuclear refueling outage timing, fewer non-refueling outage days and higher capacity revenues and increased load volumes served, partially offset by higher oil inventory write-downs in 2016.



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*Midwest*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$15 million increase in revenue net of purchased power and fuel expense in the Midwest primarily reflects nuclear refueling outage timing, fewer non-refueling outage days and higher capacity revenues, partially offset by lower realized energy prices.

*New England*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$77 million decrease in revenue net of purchased power and fuel expense in New England was driven by lower realized energy prices, higher oil inventory write-downs in 2016, and lower generation volumes from power purchase agreements.

*New York*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$59 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to lower realized energy prices, lower capacity revenues, and the amortization of contracts recorded at fair value associated with prior acquisitions, partially offset by nuclear refueling outage timing and fewer non-refueling outage days.

*ERCOT*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$6 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to higher generation volumes from renewable facilities and the amortization of contracts recorded at fair value associated with prior acquisitions, partially offset by lower generation from fossil facilities.

*Other Power Regions*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$30 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily due to the amortization of contracts recorded at fair value associated with prior acquisitions, and higher generation volumes.

*Proprietary Trading*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$1 million decrease in revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to decreased congestion activity.

*Mark-to-market*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were \$103 million for the three months ended March 31, 2016 compared to gains of \$162 million for the three months ended March 31, 2015. See Notes 8 Fair Value of Financial Assets and Liabilities and 9 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

*Other*

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The \$19 million decrease in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions and decreased gas sales, partially offset by an increase in distributed generation and energy efficiency activity.



**Table of Contents***Nuclear Fleet Capacity Factor*

The following table presents nuclear fleet operating data for the three months ended March 31, 2016 as compared to the same period in 2015, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
Nuclear fleet capacity factor <sup>(a)</sup>	95.8%	92.7%

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon.

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The nuclear fleet capacity factor increased primarily due to nuclear refueling outage timing and fewer non-refueling outage days, excluding Salem outages, during the three months ended March 31, 2016 compared to the same period in 2015. For the three months ended March 31, 2016 and 2015, planned refueling outage days totaled 70 and 89, respectively. During the same periods, non-refueling outage days totaled 10 and 32, respectively.

*Operating and Maintenance*

The changes in operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	<b>Increase (Decrease)</b>
Labor, other benefits, contracting, materials	\$ 7
Nuclear refueling outage costs, including the co-owned Salem plants	(7)
Corporate allocations	(1)
Allowance for uncollectible accounts	2
Merger and integration costs <sup>(a)</sup>	15
Merger commitments	3
Pension and non-pension postretirement benefits expense	(11)
Impairment of long-lived assets <sup>(b)</sup>	119
Cost management program <sup>(c)</sup>	18
Other	11
<b>Increase in operating and maintenance expense</b>	<b>\$ 156</b>

(a) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses, integration activities, upfront credit facilities fees, and certain pre-acquisition contingencies, and the PHI acquisition.

(b) Primarily relates to the impairment of Upstream assets in 2016.

(c) Represents the severance expense and reorganization costs related to a cost management program in 2016

*Depreciation and Amortization*

The increase in depreciation and amortization expense for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 is primarily due to increased nuclear decommissioning amortization and ongoing capital expenditures.



**Table of Contents*****Taxes Other Than Income***

Taxes other than income for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 remained relatively stable.

***Interest Expense***

Interest expense for three months ended March 31, 2016 compared to the three months ended March 31, 2015 remained relatively stable.

***Other, Net***

Other, net for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 remained relatively stable. Other, net primarily reflects the change in the realized and unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects \$20 million and \$23 million for the three months ended March 31, 2016 and 2015, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 12 Nuclear Decommissioning of the Combined Notes to the Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three months ended March 31, 2016 and 2015:

	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
Net unrealized gains on decommissioning trust funds	\$ 52	\$ 40
Net realized gains on sale of decommissioning trust funds	3	6
<b><i>Equity in Losses of Unconsolidated Affiliates</i></b>		

Equity in losses of unconsolidated affiliates for the three months ended March 31, 2016 compared to the three months ended March 31, 2015 remained relatively stable.

***Effective Income Tax Rate***

Generation s effective income tax rate was 36.7% and 31.8% for the three months ended March 31, 2016 and 2015, respectively. See Note 11 Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

**Table of Contents****Results of Operations ComEd**

	Three Months Ended March 31,		Favorable (Unfavorable)
	2016	2015	Variance
<b>Operating revenues</b>	\$ 1,249	\$ 1,185	\$ 64
<b>Purchased power expense</b>	348	327	(21)
<b>Revenue net of purchased power expense<sup>(a)(b)</sup></b>	901	858	43
<b>Other operating expenses</b>			
Operating and maintenance	368	378	10
Depreciation and amortization	189	175	(14)
Taxes other than income	75	75	
Total other operating expenses	632	628	(4)
<b>Gain on sales of assets</b>	5		5
<b>Operating income</b>	274	230	44
<b>Other income and (deductions)</b>			
Interest expense, net	(86)	(84)	(2)
Other, net	4	3	1
Total other income and (deductions)	(82)	(81)	(1)
<b>Income before income taxes</b>	192	149	43
<b>Income taxes</b>	77	59	(18)
<b>Net income</b>	\$ 115	\$ 90	\$ 25

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) For regulatory recovery mechanisms, including ComEd's electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

**Net Income**

*Three months ended March 31, 2016 Compared to Three months ended March 31, 2015.* ComEd's net income for the three months ended March 31, 2016 was higher than the same period in 2015, primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment), partially offset by unfavorable weather.

**Operating Revenue Net of Purchased Power Expense**

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There are certain drivers of Operating revenue that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on Revenue net of purchased power expense. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information on ComEd's electricity procurement process.

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All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd's volume of deliveries, but do affect ComEd's Operating revenue related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three months ended March 31, 2016, compared to the same period in 2015, consisted of the following:

	Three Months Ended March 31,	
	2016	2015
Electric	73%	78%

Retail customers purchasing electric generation from competitive electric generation suppliers at March 31, 2016 and 2015 consisted of the following:

	March 31, 2016		March 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,649,700	42%	2,406,300	62%

Under an Illinois law allowing municipalities to arrange the purchase of electricity for their participating residents, the City of Chicago previously participated in ComEd's customer choice program and arranged the purchase of electricity from Constellation (formerly Integrys), for those participating residents. In September 2015, the City of Chicago discontinued its participation in the customer choice program and many of those participating residents resumed their purchase of electricity from ComEd. ComEd's Operating revenue has increased as a result of the City of Chicago switching, but that increase is fully offset in Purchased power expense.

The changes in ComEd's Revenue net of purchased power expense for the three months ended March 31, 2016, compared to the same period in 2015 consisted of the following:

	Increase (Decrease)
Weather	\$ (20)
Volume	(4)
Electric distribution revenue	44
Transmission revenue	37
Regulatory required programs	(18)
Uncollectible accounts recovery, net	(13)
Pricing and customer mix	11
Other	6
Total increase (decrease)	\$ 43

*Weather.* The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as favorable weather conditions because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the three months ended March 31, 2016, unfavorable weather conditions reduced Operating revenue net of purchased power expense when compared to the same period in 2015.

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



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significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the three months ended March 31, 2016, and 2015, consisted of the following:

	Three Months Ended March 31,			% Change	
	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days					
Heating Degree-Days	2,900	3,632	3,164	(20.2)%	(8.3)%
Cooling Degree-Days				n/a	n/a

*Volume.* Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer, primarily due to the impacts of energy efficiency programs, as compared to the same three month period in 2015.

*Electric Distribution Revenue.* EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under EIMA, electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. ComEd's allowed ROE is the annual average rate on 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on revenue. During the three months ended March 31, 2016, ComEd recorded increased electric distribution revenue primarily due to increased capital investment and higher Operating and maintenance and Depreciation and amortization expense. See Operating and maintenance expense and Depreciation and amortization expense discussions below, and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Transmission Revenue.* Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. For the three months ended March 31, 2016, ComEd recorded increased transmission revenue due to increased capital investment and an increase in the highest daily peak load. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Regulatory Required Programs.* This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

*Uncollectible Accounts Recovery, Net.* Uncollectible accounts recovery, net represents recoveries under ComEd's uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

*Pricing and Customer Mix.* The increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes for the three months ended March 31, 2016, as compared to the same period in 2015.

*Other.* Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites, and recoveries of energy procurement costs.



**Table of Contents****Operating and Maintenance Expense**

	Three Months Ended March 31,		Increase (Decrease)
	2016	2015	
Operating and maintenance expense baseline	\$ 331	\$ 323	\$ 8
Operating and maintenance expense regulatory required program <sup>(a)</sup>	37	55	(18)
<b>Total operating and maintenance expense</b>	<b>\$ 368</b>	<b>\$ 378</b>	<b>\$ (10)</b>

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenue.

The changes in Operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	\$ 1
Pension and non-pension postretirement benefits expense <sup>(a)</sup>	(5)
Storm-related costs	9
Uncollectible accounts expense provision <sup>(b)</sup>	(1)
Uncollectible accounts expense recovery, net <sup>(b)</sup>	(12)
BSC allocations <sup>(c)</sup>	18
Other	(2)
	8
Regulatory required programs	
Energy efficiency and demand response programs	(18)
	(18)
<b>Total increase (decrease)</b>	<b>\$ (10)</b>

(a) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates in 2016.

(b) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three months ended March 31, 2016, ComEd recorded a net decrease in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting decrease has been recognized in operating revenue for the periods presented.

(c) Primarily reflects increased information technology support services from BSC during 2016.

**Depreciation and Amortization Expense**

The increase in Depreciation and amortization expense during the three months ended March 31, 2016, compared to the same period in 2015, consisted of the following:

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	<b>Increase (Decrease)</b>
Depreciation expense <sup>(a)</sup>	\$ 13
Amortization regulatory assets	(2)
Other	3
Total increase (decrease)	\$ 14

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

**Table of Contents*****Taxes Other Than Income***

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes were consistent during the three months ended March 31, 2016, compared to the same period in 2015.

***Gain on Sales of Assets***

The increase in Gain on sales of assets during the three months ended March 31, 2016, compared to the same period in 2015, is primarily due to the sale of land during March 2016.

***Interest Expense, Net***

Interest expense, net remained relatively consistent during the three months ended March 31, 2016, compared to the same period in 2015.

***Effective Income Tax Rate***

ComEd's effective income tax rate was 40.1% and 39.6% for the three months ended March 31, 2016 and 2015, respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

***ComEd Electric Operating Statistics and Revenue Detail***

Retail Deliveries to Customers (in GWs)	Three Months Ended March 31,			Weather-Normal % Change
	2016	2015	% Change	
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	6,376	6,997	(8.9)%	(2.6)%
Small commercial & industrial	7,879	8,161	(3.5)%	(0.2)%
Large commercial & industrial	6,756	6,877	(1.8)%	1.3%
Public authorities & electric railroads	361	379	(4.7)%	(0.8)%
Total retail deliveries	21,372	22,414	(4.6)%	(0.5)%

Number of Electric Customers	As of March 31,	
	2016	2015
Residential	3,566,896	3,511,271
Small commercial & industrial	372,254	369,424
Large commercial & industrial	1,955	1,966
Public authorities & electric railroads	4,821	4,843
Total	3,945,926	3,887,504

Electric Revenue Retail Sales <sup>(a)</sup>	Three Months Ended March 31,		
	2016	2015	% Change
Residential	\$ 609	\$ 568	7.2%
Small commercial & industrial	321	338	(5.0)%
Large commercial & industrial	107	109	(1.8)%
Public authorities & electric railroads	12	12	%

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Total retail	1,049	1,027	2.1%
Other revenue <sup>(b)</sup>	200	158	26.6%
Total electric revenue	\$ 1,249	\$ 1,185	5.4%

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- (a) Reflects delivery revenue and volume from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier, as all customers are assessed delivery charges. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.
- (b) Other revenue primarily includes transmission revenue from PJM. Other revenue also includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of remediation costs associated with MGP sites.

**Results of Operations PECO**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2016	2015	
<b>Operating revenues</b>	\$ 841	\$ 985	\$ (144)
<b>Purchased power and fuel</b>	321	438	117
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	520	547	(27)
<b>Other operating expenses</b>			
Operating and maintenance	215	222	7
Depreciation and amortization	67	62	(5)
Taxes other than income	42	41	(1)
Total other operating expenses	324	325	1
<b>Gain on sales of assets</b>		1	(1)
<b>Operating income</b>	196	223	(27)
<b>Other income and (deductions)</b>			
Interest expense, net	(31)	(28)	(3)
Other, net	2	2	
Total other income and (deductions)	(29)	(26)	(3)
<b>Income before income taxes</b>	167	197	(30)
<b>Income taxes</b>	43	58	15
<b>Net income attributable to common shareholder</b>	\$ 124	\$ 139	\$ (15)

- (a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not presentations defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

**Net Income attributable to common shareholder**

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* PECO's net income attributable to common shareholder decreased from the same period in 2015, primarily due to a decrease in revenue net of purchased power and fuel expense as a result

of unfavorable weather partially offset by increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016.

***Operating Revenues Net of Purchased Power and Fuel Expense***

Electric and gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to

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adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenue net of purchased power and fuel expense.

Electric and gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mcf sales, respectively) for the three months ended March 31, 2016 and 2015, consisted of the following:

	Three Months Ended March 31,	
	2016	2015
Electric	69%	67%
Natural Gas	25%	23%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at March 31, 2016 and 2015 consisted of the following:

	March 31, 2016		March 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	570,000	35%	551,000	34%
Natural Gas	80,600	16%	80,200	16%

The changes in PECO's operating revenues net of purchased power and fuel expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ (40)	\$ (32)	\$ (72)
Volume	4	5	9
Pricing	56	(1)	55
Regulatory required programs	(18)		(18)
Other	(2)	1	(1)
Total increase (decrease)	\$	\$ (27)	\$ (27)

*Weather.* The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in PECO's service territory.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three months ended March 31, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

Heating and Cooling Degree-Days	Three Months Ended			% Change	
	March 31,		Normal	2016 vs. 2015	2016 vs. Normal
	2016	2015			
Heating Degree-Days	2,137	2,934	2,477	(27.2)%	(13.7)%
Cooling Degree-Days	5		1	n/a	400.0%

*Volume.* The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three months ended March 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for electric and gas and a shift in the volume profile across classes from lower priced classes to higher priced classes for electric.

*Pricing.* The increase in operating revenues net of purchased power and fuel expense as a result of pricing for the three months ended March 31, 2016 compared to the same period in 2015 primarily reflects an increase in electric distribution rates charged to customers. The increase in electric distribution rates was effective January 1, 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements in the 2015 Form 10-K for further information.

*Regulatory Required Programs.* This represents the change in operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. The decrease in revenue from regulatory required programs for the three months ended March 31, 2016 compared to the same period in 2015 is primarily the result of smart meter costs reflected in base rates in accordance with the 2015 PAPUC approved electric distribution rate case settlement effective January 1, 2016. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

*Other.* Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

**Operating and Maintenance Expense**

	Three Months Ended		Increase (Decrease)
	March 31,		
	2016	2015	
Operating and maintenance expense baseline	\$ 195	\$ 196	\$ (1)
Operating and maintenance expense regulatory required programs <sup>(a)</sup>	20	26	(6)
Total operating and maintenance expense	\$ 215	\$ 222	\$ (7)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenue.



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The changes in operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	<b>Increase (Decrease)</b>
Baseline	
Labor, other benefits, contracting and materials	\$ (2)
Storm-related costs	3
Pension and non-pension postretirement benefits expense	(1)
PHI merger and integration costs	3
BSC allocation <sup>(a)</sup>	11
Uncollectible accounts expense	(17)
Other	2
	(1)
Regulatory Required Programs	
Smart Meter	(7)
Energy Efficiency	2
Other	(1)
	(6)
Total increase (decrease)	\$ (7)

(a) Primarily reflects increased information technology support services from BSC during 2016.

***Depreciation and Amortization Expense***

The changes in depreciation and amortization expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	<b>Increase (Decrease) 2016 vs. 2015</b>
Depreciation and amortization expense <sup>(a)</sup>	\$ 2
Regulatory asset amortization <sup>(b)</sup>	3
Total increase (decrease)	\$ 5

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

(b) Regulatory asset amortization increased for the three months ended March 31, 2016 compared to the same periods in 2015 due to an increase in regulatory asset amortization related to AMI programs and CAP Arrearage.

***Taxes Other Than Income***

Taxes other than income for the three months ended March 31, 2016 compared to the same period in 2015 remained relatively consistent.

***Interest Expense, Net***

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The increase in Interest expense, net for the three months ended March 31, 2016 compared to the same period in 2015 primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in October 2015.

### *Other, Net*

Other, net for the three months ended March 31, 2016 remained relatively consistent compared to the same period in 2015.

**Table of Contents****Effective Income Tax Rate**

PECO's effective income tax rate was 25.7% and 29.4% for the three months ended March 31, 2016 and 2015, respectively. See Note 11 – Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

**PECO Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change
	2016	2015		
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	3,415	3,968	(13.9)%	1.3%
Small commercial & industrial	2,025	2,162	(6.3)%	4.8%
Large commercial & industrial	3,594	3,734	(3.7)%	(3.1)%
Public authorities & electric railroads	227	228	(0.4)%	(0.4)%
Total retail deliveries	9,261	10,092	(8.2)%	0.3%

Number of Electric Customers	As of March 31,	
	2016	2015
Residential	1,449,470	1,439,005
Small commercial & industrial	149,388	149,192
Large commercial & industrial	3,092	3,102
Public authorities & electric railroads	9,807	9,771
Total	1,611,757	1,601,070

Electric Revenue	Three Months Ended March 31,		% Change
	2016	2015	
<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$ 410	\$ 450	(8.9)%
Small commercial & industrial	119	115	3.5%
Large commercial & industrial	58	53	9.4%
Public authorities & electric railroads	8	8	%
Total retail	595	626	(5.0)%
Other revenue <sup>(b)</sup>	49	51	(3.9)%
Total electric revenue	\$ 644	\$ 677	(4.9)%

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.

**Table of Contents****PECO Gas Operating Statistics and Revenue Detail**

	Three Months Ended March 31,			Weather
	2016	2015	% Change	- Normal % Change
<b>Deliveries to Customers (in mmcf)</b>				
<b>Retail Delivery</b>				
Retail sales <sup>(a)</sup>	27,111	34,863	(22.2)%	4.6%
Transportation and other	7,696	8,696	(11.5)%	1.4%
Total gas deliveries	34,807	43,559	(20.1)%	4.0%

	As of March 31,	
	2016	2015
<b>Number of Gas Customers</b>		
Residential	468,808	464,344
Commercial & industrial	43,313	42,941
Total retail	512,121	507,285
Transportation	817	847
Total	512,938	508,132

	Three Months Ended March 31,		
	2016	2015	% Change
<b>Gas Revenue</b>			
<b>Retail Sales</b>			
Retail sales <sup>(a)</sup>	\$ 187	\$ 296	(36.8)%
Transportation and other	10	12	(16.7)%
Total gas revenues	\$ 197	\$ 308	(36.0)%

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

**Table of Contents****Results of Operations BGE**

	Three Months Ended March 31,		Favorable (Unfavorable)
	2016	2015	Variance
<b>Operating revenues</b>	\$ 929	\$ 1,036	\$ (107)
<b>Purchased power and fuel</b>	373	487	114
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	556	549	7
<b>Other operating expenses</b>			
Operating and maintenance	202	182	(20)
Depreciation and amortization	109	106	(3)
Taxes other than income	58	57	(1)
Total other operating expenses	369	345	(24)
<b>Operating income</b>	187	204	(17)
<b>Other income and (deductions)</b>			
Interest expense, net	(24)	(25)	1
Other, net	4	4	
Total other income and (deductions)	(20)	(21)	1
<b>Income before income taxes</b>	167	183	(16)
<b>Income taxes</b>	66	74	8
<b>Net income</b>	101	109	(8)
Preference stock dividends	3	3	
<b>Net income attributable to common shareholder</b>	\$ 98	\$ 106	\$ (8)

(a) BGE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of purchased fuel expense for gas sales. BGE believes revenue net of purchased power and revenue net of purchased fuel are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies presentations or more useful than the GAAP information provided elsewhere in this report.

**Net Income Attributable to Common Shareholder**

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* BGE's net income attributable to common shareholder for the three months ended March 31, 2016 was lower than the same period in 2015, primarily due to an increase in operating and maintenance expense as a result of increased storm costs in BGE's service territory.

**Operating Revenues Net of Purchased Power and Fuel Expense**

There are certain drivers to Operating revenue that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric generation or natural gas supplier. Operating revenue and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to

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customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

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Electric and gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to select a competitive electric generation or natural gas supplier. All BGE customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three months ended March 31, 2016, compared to the same period in 2015, consisted of the following:

	Three Months Ended March 31,	
	2016	2015
Electric	57%	56%
Natural Gas	49%	45%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at March 31, 2016 and 2015 consisted of the following:

	March 31, 2016		March 31, 2015	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	341,800	27%	355,000	28%
Natural Gas	153,500	23%	158,000	24%

The changes in BGE's operating revenues net of purchased power and fuel expense for the three months ended March 31, 2016, compared to the same period in 2015, consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Regulatory required programs	\$ (1)	\$ (1)	\$ (2)
Transmission revenue	12		12
Other	3	(6)	(3)
Total increase (decrease)	\$ 14	\$ (7)	\$ 7

*Revenue Decoupling.* The demand for electricity and gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in consumption levels. This allows BGE to recognize revenue at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. Therefore, while this revenue is affected by customer growth, it will not be affected by actual weather or usage conditions. BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Three Months Ended			% Change	
	March 31,			2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days	2016	2015	Normal		
Heating Degree-Days	2,280	2,950	2,412	(22.7)%	(5.5)%
Cooling Degree-Days				n/a	n/a

*Regulatory Required Programs.* This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Taxes other than income in BGE's Consolidated Statements of Operations and Comprehensive Income.

*Transmission Revenue.* Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the three months ended March 31, 2016 compared to the same period in 2015, the increase in transmission revenue was primarily due to an increase in capital investment and operating and maintenance expense. See Operating and Maintenance Expense below and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Other.* Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

**Operating and Maintenance Expense**

The changes in operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials	\$ 2
Storm-related costs	17
Uncollectible accounts expense <sup>(a)</sup>	(13)
City of Baltimore conduit lease <sup>(b)</sup>	7
BSC allocations <sup>(c)</sup>	7
Total increase (decrease)	\$ 20

(a) Uncollectible accounts decreased primarily due to milder weather and improved customer behavior for the three months ended March 31, 2016 compared to the same period in 2015.

(b) City of Baltimore conduit fees increased for the three months ended March 31, 2016 compared to the same period in 2015 as a result of increased rental fees assessed by the City of Baltimore. See Executive Overview Environmental Legislative and Regulatory Developments above and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(c) Primarily reflects increased information technology support services from BSC during 2016.



**Table of Contents*****Depreciation and Amortization***

The changes in depreciation and amortization expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	<b>Increase (Decrease)</b>
Depreciation expense <sup>(a)</sup>	\$ 4
Regulatory asset amortization <sup>(b)</sup>	(1)
<b>Total increase (decrease)</b>	<b>\$ 3</b>

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

(b) Regulatory asset amortization decreased for the three months ended March 31, 2016 compared to the same periods in 2015 due to a reduction in regulatory asset amortization related to demand response programs.

***Taxes Other Than Income***

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three months ended March 31, 2016 compared to the same period in 2015 remained relatively consistent.

***Interest Expense, Net***

Interest expense, net remained relatively consistent during the three months ended March 31, 2016, compared to the same period in 2015 .

***Effective Income Tax Rate***

BGE s effective income tax rate was 39.5% and 40.4% for the three months ended March 31, 2016 and 2015, respectively. See Note 11 – Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Table of Contents****BGE Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,			Weather - Normal % Change
	2016	2015	% Change	
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	3,479	4,173	(16.6)%	n.m.
Small commercial & industrial	774	845	(8.4)%	n.m.
Large commercial & industrial	3,219	3,439	(6.4)%	n.m.
Public authorities & electric railroads	71	75	(5.3)%	n.m.
<b>Total electric deliveries</b>	<b>7,543</b>	<b>8,532</b>	<b>(11.6)%</b>	<b>n.m.</b>

Number of Electric Customers	As of March 31,	
	2016	2015
Residential	1,141,814	1,131,621
Small commercial & industrial	113,034	112,811
Large commercial & industrial	11,932	11,777
Public authorities & electric railroads	282	286
<b>Total</b>	<b>1,267,062</b>	<b>1,256,495</b>

Electric Revenue	Three Months Ended March 31,			% Change
	2016	2015		
<b>Retail Sales<sup>(a)</sup></b>				
Residential	\$ 428	\$ 449	(4.7)%	
Small commercial & industrial	73	76	(3.9)%	
Large commercial & industrial	100	120	(16.7)%	
Public authorities & electric railroads	9	8	12.5%	
Total retail	610	653	(6.6)%	
Other revenue	70	60	16.7%	
Total electric revenue	\$ 680	\$ 713	(4.6)%	

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

**Table of Contents****BGE Gas Operating Statistics and Revenue Detail**

Deliveries to Customers (in mmcf)	Three Months Ended March 31,		% Change	Weather - Normal % Change
	2016	2015		
<b>Retail Deliveries<sup>(a)</sup></b>				
Retail sales	38,584	46,877	(17.7)%	n.m.
Transportation and other <sup>(b)</sup>	2,496	3,325	(24.9)%	n.m.
Total gas deliveries	41,080	50,202	(18.2)%	n.m.
	As of March 31,			
<b>Number of Gas Customers</b>	<b>2016</b>	<b>2015</b>		
Residential	619,130	612,814		
Commercial & industrial	44,224	44,199		
Total	663,354	657,013		
	Three Months Ended March 31,			
<b>Gas Revenue</b>	<b>2016</b>	<b>2015</b>	<b>% Change</b>	
<b>Retail Sales<sup>(a)</sup></b>				
Retail sales	\$ 238	\$ 299	(20.4)%	
Transportation and other <sup>(b)</sup>	11	24	(54.2)%	
Total gas revenues	\$ 249	\$ 323	(22.9)%	

(a) Reflects delivery volumes and revenue from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(b) Transportation and other gas revenue includes off-system revenue of 2,496 mmcfs (\$9 million) and 3,325 mmcfs (\$23 million) for the three months ended March 31, 2016 and 2015, respectively.

**Results of Operations PHI**

PHI's results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For Predecessor reporting periods, PHI's results of operations also include the results of PES and PCI. See Note 20 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI's reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

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As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The Predecessor reporting periods represent PHI's results of operations for the three months ended March 31, 2015 and the period of January 1, 2016 to March 23, 2016. The Successor reporting period represents PHI's results of operations for the period of March 24, 2016 to March 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	<i>Successor</i>		<i>Predecessor</i>	
	<b>March 24, 2016 to March 31, 2016</b>	<b>January 1, 2016 to March 23, 2016</b>	<b>Three Months Ended March 31, 2015</b>	<b>Favorable (Unfavorable) Variance</b>
<b>Operating revenues</b>	\$ 105	\$ 1,153	\$ 1,354	\$ (201)
<b>Purchased power and fuel</b>	38	497	639	142
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	67	656	715	(59)
<b>Other operating expenses</b>				
Operating and maintenance	449	294	300	6
Depreciation and amortization	14	152	155	3
Taxes other than income	15	105	118	13
Total other operating expenses	478	551	573	22
<b>Operating (loss) income</b>	(411)	105	142	(37)
<b>Other income and (deductions)</b>				
Interest expense, net	(6)	(65)	(68)	3
Other, net	2	(4)	9	(13)
Total other income and (deductions)	(4)	(69)	(59)	(10)
<b>(Loss) income before income taxes</b>	(415)	36	83	(47)
<b>Income taxes</b>	(106)	17	30	13
<b>Net (loss) income attributable to membership interest/common shareholders</b>	\$ (309)	\$ 19	\$ 53	\$ (34)

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. PHI believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

**Successor Period March 24, 2016 to March 31, 2016**

PHI's net loss attributable to membership interest for the Successor period of March 24, 2016 to March 31, 2016 was \$309 million. There were no significant changes in the underlying trends affecting PHI's results of operations during the Successor period March 24, 2016 to March 31, 2016 except for the pre-tax recording of \$418 million of non-recurring merger-related costs within Operating and maintenance expense.

**Predecessor Period January 1, 2016 to March 23, 2016 Compared to the Three Months Ended March 31, 2015****Net Income Attributable to Common Shareholders**

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PHI's net income attributable to common shareholders was \$19 million for the period January 1, 2016 to March 23, 2016 as compared to \$53 million for the three months ended March 31, 2015.

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***Revenue Net of Purchased Power and Fuel Expense***

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed above, decreased by \$59 million for the period January 1, 2016 to March 23, 2016 as compared to the three months ended March 31, 2015. The decrease is attributable to the following factors:

Decrease of \$10 million at Pepco primarily related to electric distribution revenue decreases totaling \$14 million due to less days of activity in 2016 compared to 2015 and \$4 million lower transmission revenue due to lower days of activity, partially offset by an increase in transmission revenue from an estimated higher rate effective June 1, 2015. These decreases were partially offset by an increase in distribution revenue of \$8 million due to an EmPower Maryland rate increase effective February 2015.

Decrease of \$22 million at DPL primarily related to electric distribution revenue decreases totaling \$13 million and natural gas distribution revenues totaling \$7 million due to milder weather and less days of activity in 2016 compared to 2015, a decrease of \$3 million associated with the Renewable Portfolio Surcharge in Delaware, partially offset by an increase of \$2 million due to an EmPower Maryland rate increase effective February 2015.

Decrease of \$14 million at ACE primarily related to milder weather and less days of activity in 2016 compared to 2015.

Decrease of \$12 million at PES primarily related to a loss on a construction contract, lower thermal service volumes in 2016 and to less days of activity in 2016 compared to 2015.

***Operating and Maintenance Expense***

Operating and maintenance expense decreased by \$6 million for the period January 1, 2016 to March 23, 2016 as compared to the three months ended March 31, 2015. The decrease is attributable to the following factors:

Decrease of \$22 million at Pepco, DPL and ACE primarily due to lower labor, contracting and material costs related to the implementation of a new customer information system in 2015 and less days of activity in 2016 compared to 2015.

Decrease of \$6 million at PES primarily due to less days of activity in 2016 compared to 2015 and non-recurring costs incurred in 2015.

Increase of \$22 million at Corporate due primarily to Merger-related transaction and integration costs.

***Depreciation and Amortization Expense***

Depreciation and amortization expense decreased by \$3 million primarily due to a decrease of \$6 million in the amortization of regulatory assets and lower depreciation of \$2 million due to less days of activity in 2016 compared to 2015, partially offset by higher plant balances at all operating companies. These decreases were partially offset by an increase of \$6 million associated with the EmPower Maryland surcharge rate increase effective February 2015.

***Taxes Other Than Income***

Taxes other than income decreased by \$13 million primarily due to lower utility taxes that are collected and passed through by Pepco and DPL of \$9 million resulting from less days of activity in 2016 compared to 2015 and lower property taxes in Maryland of \$4 million.

***Interest Expense, Net***

Interest expense decreased by \$3 million due to lower days of activity in 2016 compared to 2015.

**Table of Contents****Other, Net**

Other, net decreased by \$13 million primarily due to the preferred stock derivative expense of \$18 million, partially offset by increased income of \$3 million from AFUDC equity.

**Effective Income Tax Rate**

PHI's effective income tax rates for the period January 1, 2016 to March 23, 2016 and for the three months ended March 31, 2015 were 47.2% and 36.1%, respectively. See Note 11 – Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

**Results of Operations – Pepco**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2016	2015	
<b>Operating revenues</b>	\$ 551	\$ 545	\$ 6
<b>Purchased power expense</b>	197	211	14
<b>Revenue net of purchased power expense<sup>(a)</sup></b>	354	334	20
<b>Other operating expenses</b>			
Operating and maintenance	290	113	(177)
Depreciation and amortization	75	62	(13)
Taxes other than income	94	96	2
Total other operating expenses	459	271	(188)
<b>Operating (loss) income</b>	(105)	63	(168)
<b>Other income and (deductions)</b>			
Interest expense, net	(37)	(30)	(7)
Other, net	9	5	4
Total other income and (deductions)	(28)	(25)	(3)
<b>(Loss) income before income taxes</b>	(133)	38	(171)
<b>Income taxes</b>	(25)	12	37
<b>Net (loss) income attributable to common shareholder</b>	\$ (108)	\$ 26	\$ (134)

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

**Net Income Attributable to Common Shareholder**

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* Pepco's net income attributable to common shareholder for the three months ended March 31, 2016, was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense due to merger-related costs.



***Operating Revenue Net of Purchased Power Expense***

Operating revenues include revenue from the distribution and supply of electricity to Pepco's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

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Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers' choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three months ended March 31, 2016, compared to the same period in 2015, consisted of the following:

	Three Months Ended March 31,	
	2016	2015
Electric	65%	61%

Retail customers purchasing electric generation from competitive electric generation suppliers at March 31, 2016 and 2015 consisted of the following:

	March 31, 2016		March 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	173,221	21%	166,127	20%

Retail deliveries purchased from competitive electric generation suppliers represented 73% of Pepco's retail kWh sales to the District of Columbia customers and 58% of Pepco's retail kWh sales to Maryland customers for the three months ended March 31, 2016 and 67% of Pepco's retail kWh sales to the District of Columbia customers and 56% of Pepco's retail kWh sales to Maryland customers for the three months ended March 31, 2015.

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also include transmission enhancement credits that Pepco receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by Pepco to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in Pepco's operating revenues net of purchased power expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)
Volume	\$ 5
Regulatory required programs	13
Transmission revenue	2
Total increase (decrease)	\$ 20

*Revenue Decoupling.* Pepco's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the



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District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland and the District of Columbia, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland and the District of Columbia retail distribution sales falls short of the revenue that Pepco is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that Pepco is entitled to earn based on the approved distribution charge per customer.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in Pepco's service territory. The changes in heating and cooling degree days in Pepco's service territory for the three months ended March 31, 2016 compared to the same period in 2015 and normal weather consisted of the following:

	Three Months Ended			% Change	
	March 31,			2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days	2016	2015	Normal		
Heating Degree-Days	2,010	2,491	2,170	(19.3)%	(7.4)%
Cooling Degree-Days	3		3	n/a	%

*Volume.* The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three months ended March 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth.

*Regulatory Required Programs.* This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

*Transmission Revenue.* Transmission revenue increased as a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by a higher reserve related to the FERC ROE settlement.

**Operating and Maintenance Expense**

	Three Months Ended		Increase (Decrease)
	March 31,		
	2016	2015	
Operating and maintenance expense baseline	\$ 287	\$ 110	\$ 177
Operating and maintenance expense regulatory required program <sup>(a)</sup>	3	3	
<b>Total operating and maintenance expense</b>	<b>\$ 290</b>	<b>\$ 113</b>	<b>\$ 177</b>

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.



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The changes in operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	<b>Increase (Decrease)</b>
Baseline	
Labor, other benefits, contracting and materials	\$ 7
Storm-related costs	2
BSC and PHISCO allocations <sup>(a)</sup>	29
Merger commitments <sup>(b)</sup>	139
Total increase (decrease)	\$ 177

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

**Depreciation and Amortization Expense**

The changes in depreciation and amortization expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	<b>Increase (Decrease)</b>
Depreciation expense <sup>(a)</sup>	\$ 2
Regulatory asset amortization <sup>(b)</sup>	11
Total increase (decrease)	\$ 13

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

(b) Regulatory asset amortization increased for the three months ended March 31, 2016 compared to the same period in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015.

**Taxes Other Than Income**

Taxes other than income for the three months ended March 31, 2016 compared to the same period in 2015 decreased primarily due to lower property taxes in Maryland.

**Interest Expense, Net**

Interest expense, net for the three months ended March 31, 2016 compared to the same period in 2015 increased \$7 million primarily due to the recording of interest expense for an uncertain tax position in 2016.

**Other, Net**

Other, net for the three months ended March 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC.

**Effective Income Tax Rate**

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Pepco's effective income tax rate was 18.8% and 31.6% for the three months ended March 31, 2016 and 2015, respectively. See Note 11 - Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates. As a result of the merger, Pepco recorded an after-tax charge of \$33 million during the three months ended March 31, 2016 as a result of assessment and remeasurement of certain federal and state uncertain tax positions.

**Table of Contents****Pepco Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,		% Change	Weather - Normal % Change
	2016	2015		
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	2,218	2,590	(14.4)%	(3.5)%
Small commercial & industrial	381	464	(17.9)%	(1.5)%
Large commercial & industrial	3,945	3,607	9.4%	(0.7)%
Public authorities & electric railroads	189	185	2.2%	(0.4)%
Total retail deliveries	6,733	6,846	(1.7)%	(1.7)%

Number of Electric Customers	As of March 31,	
	2016	2015
Residential	769,934	739,321
Small commercial & industrial	53,853	53,303
Large commercial & industrial	20,996	20,102
Public authorities & electric railroads	126	126
Total	844,909	812,852

Electric Revenue	Three Months Ended March 31,		% Change
	2016	2015	
<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$ 255	\$ 261	(2.3)%
Small commercial & industrial	37	41	(9.8)%
Large commercial & industrial	200	187	7.0%
Public authorities & electric railroads	8	8	%
Total retail	500	497	0.6%
Other revenue <sup>(b)</sup>	51	48	6.3%
Total electric revenue	\$ 551	\$ 545	1.1%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from Pepco and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from Pepco, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.



**Table of Contents****Results of Operations DPL**

	<b>Three Months Ended March 31,</b>		<b>Favorable (Unfavorable) Variance</b>
	<b>2016</b>	<b>2015</b>	
<b>Operating revenues</b>	\$ 362	\$ 421	\$ (59)
<b>Purchased power and fuel</b>	176	225	49
<b>Revenue net of purchased power and fuel<sup>(a)</sup></b>	186	196	(10)
<b>Other operating expenses</b>			
Operating and maintenance	204	81	(123)
Depreciation and amortization	39	39	
Taxes other than income	15	13	(2)
Total other operating expenses	258	133	(125)
<b>Operating (loss) income</b>	(72)	63	(135)
<b>Other income and (deductions)</b>			
Interest expense, net	(12)	(12)	
Other, net	3	2	1
Total other income and (deductions)	(9)	(10)	1
<b>(Loss) income before income taxes</b>	(81)	53	(134)
<b>Income taxes</b>	(9)	21	30
<b>Net (loss) income attributable to common shareholder</b>	\$ (72)	\$ 32	\$ (104)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

**Net Income Attributable to Common Shareholder**

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

**Operating Revenues Net of Purchased Power and Fuel Expense**

Operating revenues include revenue from the distribution and supply of electricity to DPL's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers' choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.



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Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three months ended March 31, 2016 and 2015, consisted of the following:

	Three Months Ended March 31,	
	2016	2015
Electric	49%	41%
Natural Gas	25%	23%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at March 31, 2016 and 2015 consisted of the following:

	March 31, 2016		March 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	77,014	14.9%	76,706	14.9%
Natural Gas	158	0.1%	160	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 51% of DPL's retail kWh sales to Delaware customers and 44% of DPL retail kWh sales to Maryland customers for the three months ended March 31, 2016 and 42% to Delaware customers and 39% to Maryland customers for the three months ended March 31, 2015.

The costs related to default electricity supply are included in Purchased power and fuel. Operating revenues also include transmission enhancement credits that DPL receives as a transmission owner from PJM in consideration for approved regional transmission expansion plan expenditures.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Natural Gas operating revenue includes sources that are subject to price regulation (Regulated Gas Revenue) and those that generally are not subject to price regulation (Other Gas Revenue). Regulated gas revenue includes the revenue DPL receives from on-system natural gas delivered sales and the transportation of natural gas for customers within its service territory at regulated rates. Other gas revenue consists of off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers. Off-system sales are made possible when low demand for natural gas by regulated customers creates excess pipeline capacity.

Purchased power consists of the cost of electricity purchased by DPL to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders. Purchased fuel consists of the cost of gas purchased by DPL to fulfill its obligation to regulated gas customers and, as such, is recoverable from customers in accordance with the terms of public service commission orders. It also includes the cost of gas purchased for off-system sales.

The changes in DPL's operating revenues net of purchased power and fuel expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ (7)	\$ (8)	\$ (15)
Volume	2	2	4
Regulatory required programs	(1)		(1)
Transmission revenue	3		3
Other	(1)		(1)

Total increase (decrease)

\$ (4)

\$ (6)

\$ (10)

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**Revenue Decoupling.** DPL's results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer's volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland retail distribution sales falls short of the revenue that DPL is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that DPL is entitled to earn based on the approved distribution charge per customer.

**Weather.** The demand for electricity and gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the three months ended March 31, 2016 compared to the same period in 2015, operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in DPL's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL's electric service territory and a 30-year period in DPL's gas service territory. The changes in heating and cooling degree days in DPL's service territory for the three months ended March 31, 2016 compared to the same period in 2015 and normal weather consisted of the following:

	Three Months Ended			% Change	
	March 31,			2016 vs. 2015	2016 vs. Normal
Heating and Cooling Degree-Days	2016	2015	Normal		
Heating Degree-Days	2,247	2,865	2,449	(21.6)%	(8.2)%
Cooling Degree-Days	3		1	n/a	200.0%

**Volume.** The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three months ended March 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth.

**Regulatory Required Programs.** This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

**Transmission Revenue.** Transmission revenue increased as a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by a higher reserve related to the FERC ROE settlement.

**Table of Contents****Operating and Maintenance Expense**

	Three Months Ended March 31,		Increase (Decrease)
	2016	2015	
Operating and maintenance expense baseline	\$ 201	\$ 76	\$ 125
Operating and maintenance expense regulatory required program <sup>(a)</sup>	3	5	(2)
<b>Total operating and maintenance expense</b>	<b>\$ 204</b>	<b>\$ 81</b>	<b>\$ 123</b>

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015, consisted of the following:

	Increase (Decrease)
<b>Baseline</b>	
Labor, other benefits, contracting and materials	\$ 1
Storm-related costs	3
Pension and non-pension postretirement benefits expense	1
Uncollectible accounts expense	(1)
BSC and PHISCO allocations <sup>(a)</sup>	16
Merger commitments <sup>(b)</sup>	104
Other	1
	125
Regulatory required programs	
Purchased power administrative costs	(2)
<b>Total increase (decrease)</b>	<b>\$ 123</b>

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

**Depreciation and Amortization Expense**

The changes in depreciation and amortization expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)
Depreciation expense <sup>(a)</sup>	\$ 2
Regulatory asset amortization <sup>(b)</sup>	2
Delaware renewable energy portfolio standards deferral	(4)

Total increase (decrease)

\$

- (a) Depreciation expense increased due to ongoing capital expenditures.
- (b) Regulatory asset amortization increased for the three months ended March 31, 2016 compared to the same period in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015.

***Taxes Other Than Income***

Taxes other than income for the three months ended March 31, 2016 compared to the same period in 2015 remained relatively consistent.

**Table of Contents****Interest Expense, Net**

Interest expense, net for the three months ended March 31, 2016 compared to the same period in 2015 remained relatively constant.

**Other, Net**

Other, net for the three months ended March 31, 2016 remained relatively level compared to the same period in 2015.

**Effective Income Tax Rate**

DPL's effective income tax rate was 11.1% and 39.6% for the three months ended March 31, 2016 and 2015, respectively. See Note 11 – Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. As a result of the merger, DPL recorded an after-tax charge of \$24 million during the three months ended March 31, 2016 as a result of assessment and remeasurement of certain federal and state uncertain tax positions.

**DPL Electric Operating Statistics and Revenue Detail**

	Three Months Ended March 31,			Weather - Normal % Change
	2016	2015	% Change	
<b>Retail Deliveries to Customers (in GWhs)</b>				
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	1,428	1,863	(23.3)%	(4.8)%
Small commercial & industrial	572	510	12.2%	(1.7)%
Large commercial & industrial	1,078	1,108	(2.7)%	(0.8)%
Public authorities & electric railroads	14	13	7.7%	%
Total retail deliveries	3,092	3,494	(11.5)%	(2.9)%

	As of March 31,	
	2016	2015
<b>Number of Electric Customers</b>		
Residential	453,670	451,299
Small commercial & industrial	59,860	60,486
Large commercial & industrial	1,418	1,287
Public authorities & electric railroads	643	582
Total	515,591	513,654

	Three Months Ended March 31,		
	2016	2015	% Change
<b>Electric Revenue</b>			
<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$ 182	\$ 217	(16.1)%
Small commercial & industrial	49	51	(3.9)%
Large commercial & industrial	25	23	8.7%
Public authorities & electric railroads	4	3	33.3%
Total retail	260	294	(11.6)%
Other revenue <sup>(b)</sup>	43	41	4.9%



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Total electric revenue	\$	303	\$	335	(9.6)%
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- (a) Reflects delivery volumes and revenues from customers purchasing electricity directly from DPL and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from DPL, revenue also reflects the cost of energy and transmission.
- (b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

**Table of Contents****DPL Gas Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in mmcf)	Three Months Ended March 31,		% Change	Weather - Normal % Change
	2016	2015		
<b>Retail Deliveries</b>				
Residential	6,060	7,878	(23.1)%	(7.3)%
Transportation & other	1,968	2,325	(15.4)%	(2.4)%
Total gas deliveries	8,028	10,203	(21.3)%	(6.1)%
Number of Gas Customers	As of March 31,			
	2016	2015		
Residential	120,046	118,549		
Commercial & industrial	9,772	9,556		
Transportation & other	158	160		
Total	129,976	128,265		
Gas Revenue	Three Months Ended March 31,		% Change	
	2016	2015		
<b>Retail Sales<sup>(a)</sup></b>				
Retail sales	\$ 53	\$ 79	(32.9)%	
Transportation & other <sup>(b)</sup>	6	7	(14.3)%	
Total gas revenues	\$ 59	\$ 86	(31.4)%	

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from DPL and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from DPL, revenue also reflects the cost of natural gas.

(b) Transportation and other revenue includes off-system natural gas sales and the short-term release of interstate pipeline transportation and storage capacity not needed to serve customers.

**Table of Contents****Results of Operations ACE**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2016	2015	
<b>Operating revenues</b>	\$ 291	\$ 334	\$ (43)
<b>Purchased power expense</b>	158	191	33
<b>Revenue net of purchased power expense<sup>(a)</sup></b>	133	143	(10)
<b>Other operating expenses</b>			
Operating and maintenance	212	69	(143)
Depreciation and amortization	40	43	3
Taxes other than income	2	2	
Total other operating expenses	254	114	(140)
<b>Operating (loss) income</b>	(121)	29	(150)
<b>Other income and (deductions)</b>			
Interest expense, net	(16)	(16)	
Other, net	4	1	3
Total other income and (deductions)	(12)	(15)	3
<b>(Loss) income before income taxes</b>	(133)	14	(147)
<b>Income taxes</b>	(33)	5	38
<b>Net (loss) income attributable to common shareholder</b>	\$ (100)	\$ 9	\$ (109)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

**Net Income Attributable to Common Shareholder**

*Three Months Ended March 31, 2016 Compared to Three Months Ended March 31, 2015.* The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

**Operating Revenue Net of Purchased Power Expense**

Operating revenues include revenue from the distribution and supply of electricity to ACE's customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All ACE customers have the choice to purchase electricity from competitive electric generation suppliers. The customer's choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.



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Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three months ended March 31, 2016, compared to the same period in 2015, consisted of the following:

	Three Months Ended March 31,	
	2016	2015
Electric	47%	43%

Retail customers purchasing electric generation from competitive electric generation suppliers at March 31, 2016 and 2015 consisted of the following:

	March 31, 2016		March 31, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	73,165	13%	79,524	15%

The costs related to default electricity supply are included in Purchased power expense. Operating revenues also include revenue from Transition Bond Charges that ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds, revenue from the resale in the PJM RTO market of energy and capacity purchased under contracts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

Purchased power expense consists of the cost of electricity purchased by ACE to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in ACE's operating revenues net of purchased power expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)
Weather	\$ (7)
Regulatory required programs	(5)
Transmission revenues	3
Other	(1)
<b>Total increase (decrease)</b>	<b>\$ (10)</b>

*Weather.* The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the three months ended March 31, 2016 compared to the same period in 2015, operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE's service territory.

For retail customers of ACE, distribution revenues are not decoupled for the distribution of electricity by ACE, and thus are subject to variability due to changes in customer consumption. Therefore, changes in customer usage (due to weather conditions, energy prices, energy savings programs or other reasons) from period to period have a direct impact on reported distribution revenue for customers in ACE's service territory.



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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE's service territory. The changes in heating and cooling degree days in ACE's service territory for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

Heating and Cooling Degree-Days	Three Months Ended March 31,			% Change	
	2016	2015	Normal	2016 vs. 2015	2016 vs. Normal
Heating Degree-Days	2,270	3,041	2,523	(25.4)%	(10.0)%
Cooling Degree-Days	4		1	n/a	300.0%

*Regulatory Required Programs.* This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the depreciation and amortization expense discussion below for additional information on included programs.

*Transmission Revenue.* Transmission revenue increased as a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by a higher reserve related to the FERC ROE settlement.

**Operating and Maintenance Expense**

Operating and maintenance expense	baseline	Three Months Ended March 31,		Increase (Decrease)
		2016	2015	
Operating and maintenance expense	regulatory required programs <sup>(a)</sup>	\$ 211	\$ 68	\$ 143
		1	1	
<b>Total operating and maintenance expense</b>		<b>\$ 212</b>	<b>\$ 69</b>	<b>\$ 143</b>

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	\$ 12
BSC and PHISCO allocations <sup>(a)</sup>	13
Uncollectible accounts expense	2
Merger commitments <sup>(b)</sup>	120
Other	(4)
<b>Total increase (decrease)</b>	<b>\$ 143</b>

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.



**Table of Contents*****Depreciation and Amortization Expense***

The changes in depreciation and amortization expense for the three months ended March 31, 2016 compared to the same period in 2015 consisted of the following:

	<b>Increase (Decrease)</b>
Depreciation expense <sup>(a)</sup>	\$ 1
Regulatory asset amortization <sup>(b)</sup>	(4)
<b>Total increase (decrease)</b>	<b>\$ (3)</b>

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

(b) Regulatory asset amortization decreased for the three months ended March 31, 2016 compared to the same period in 2015 as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax.

***Taxes Other Than Income***

Taxes other than income for the three months ended March 31, 2016 compared to the same period in 2015, remained relatively constant.

***Interest Expense, Net***

Interest expense, net for the three months ended March 31, 2016 compared to the same period in 2015 remained relatively constant.

***Other, Net***

Other, net for the three months ended March 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity.

***Effective Income Tax Rate***

ACE's effective income tax rate was 24.8% and 35.7%, for the three months ended March 31, 2016 and 2015, respectively. See Note 11 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. As a result of the merger, ACE recorded an after-tax charge of \$23 million during the three months ended March 31, 2016 as a result of assessment and remeasurement of certain federal uncertain tax positions.

**Table of Contents***ACE Electric Operating Statistics and Revenue Detail*

	Three Months Ended March 31,			Weather - Normal % Change
	2016	2015	% Change	
<b>Retail Deliveries to Customers (in GWs)</b>				
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	938	1,124	(16.5)%	(3.5)%
Small commercial & industrial	289	305	(5.2)%	(1.7)%
Large commercial & industrial	820	816	0.5%	(1.0)%
Public authorities & electric railroads	15	12	25.0%	%
Total retail deliveries	2,062	2,257	(8.6)%	(2.2)%

	As of March 31,	
	2016	2015
<b>Number of Electric Customers</b>		
Residential	482,718	481,354
Small commercial & industrial	60,858	61,030
Large commercial & industrial	3,828	3,814
Public authorities & electric railroads	583	553
Total	547,987	546,751

	Three Months Ended March 31,		
	2016	2015	% Change
<b>Electric Revenue</b>			
<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$ 150	\$ 175	(14.3)%
Small commercial & industrial	39	40	(2.5)%
Large commercial & industrial	51	49	4.1%
Public authorities & electric railroads	3	3	%
Total retail	243	267	(9.0)%
Other revenue <sup>(b)</sup>	48	67	(28.4)%
Total electric revenue	\$ 291	\$ 334	(12.9)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from ACE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from ACE, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

**Liquidity and Capital Resources**

Exelon activity presented below includes the activity of PHI, Pepco, DPL and ACE, from the PHI Merger effective date of March 24, 2016 through March 31, 2016. Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI's activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the three months ended March 31, 2016 and 2015. All results included throughout the liquidity

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and capital resources section are presented on a GAAP basis.

The Registrants' operating and capital expenditure requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants' businesses are capital intensive and require considerable capital resources. Each Registrant's

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access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of \$9.5 billion. In addition, Generation has \$425 million in bilateral credit facilities with banks which have various expirations dates between December 2016 and January 2019. The Registrants utilize their credit facilities to support their commercial paper programs, and provide for other short-term borrowings, term loans and letters of credit. See the *Credit Matters* section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 10 *Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements* for further discussion of the Registrants' debt and credit agreements.

**PHI Merger Financing**

Exelon funded the all-cash purchase price, acquisition and integration related costs, and merger commitments with the issuance of \$4.2 billion of debt (of which \$3.3 billion remains after execution of the exchange offer), \$1.15 billion of junior subordinated notes in the form of 23 million equity units, and \$1.9 billion of common stock, cash proceeds of \$1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately \$1.4 billion) and cash on hand and/or short-term borrowings available to Exelon. See Note 14 *Debt and Credit Agreements* and Note 19 *Shareholders' Equity* included in the Exelon 2015 Form 10-K for further information on the debt and equity issuances.

***Cash Flows from Operating Activities****General*

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants' cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE and DPL, gas distribution services. The Utility Registrants' distribution services are provided to an established and diverse base of retail customers. The Utility Registrants' future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 *Regulatory Matters* and 23 *Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2015 Form 10-K* for further discussion of regulatory and legal proceedings and proposed legislation. See Note 7 *Regulatory Matters* and Note 16 *Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the PHI 2015 Form 10-K*.

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The following table provides a summary of the major items affecting Exelon's cash flows from operations for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,		
	2016 <sup>(c)</sup>	2015	Variance
Net income	\$ 123	\$ 738	\$ (615)
Add (subtract):			
Non-cash operating activities <sup>(a)</sup>	1,942	1,282	660
Pension and other postretirement benefit contributions	(239)	(269)	30
Income taxes	47	174	(127)
Changes in working capital and other noncurrent assets and liabilities <sup>(b)</sup>	(623)	(697)	74
Option premiums received, net	17	5	12
Counterparty collateral posted, net	206	257	(51)
<b>Net cash flows provided by operations</b>	<b>\$ 1,473</b>	<b>\$ 1,490</b>	<b>\$ (17)</b>

- (a) Represents, when applicable, depreciation, amortization and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and other postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, PHI merger commitment and severance charges, and other non-cash charges. See Note 19 Supplemental Financial Information for further detail on non-cash operating activity.
- (b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.
- (c) Includes PHI Consolidated activity from March 24, 2016 to March 31, 2016.

*Pension and Other Postretirement Benefits*

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. On August 8, 2014, this funding relief was extended for five years. On November 2, 2015 the funding relief was extended for an additional three years and premiums pension plans pay to the Pension Benefit Guaranty Corporation were further increased.

OPEB funding generally follows accounting cost, subject to adjustment for other considerations such as liabilities management and regulatory implications.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

*Tax Matters*

The Registrants' future cash flows from operating activities may be affected by the following tax matters:

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon would be required to either post a bond or pay the tax and interest for the tax years before the court to appeal the decision. If an adverse decision is reached in 2016, the

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potential tax and after-tax interest, exclusive of penalties, that could become payable may be as much as \$865 million, of which approximately \$300 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity, and the

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balance at Exelon. It is expected that Exelon's remaining tax years affected by the litigation will be settled following a final appellate decision which could take several years.

In April of 2016, Exelon received tax refunds of approximately \$460 million related to IRS positions settled in prior tax years. Of this amount, approximately \$195 million of the refund is attributable to Generation and the remaining \$265 million is attributable to ComEd.

State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.

Cash flows from operations for the three months ended March 31, 2016 and 2015 by Registrant were as follows:

	Three Months Ended March 31,	
	2016	2015
Exelon	\$ 1,473	\$ 1,490
Generation	782	837
ComEd	284	251
PECO	138	158
BGE	273	281
Pepco	258	33
DPL	147	57
ACE	246	63

	<i>Successor</i>	<i>Predecessor</i>	
	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015
PHI	\$ 43	\$ 264	\$ 157

Changes in the Registrants' cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the three months ended March 31, 2016 and 2015 were as follows:

*Generation*

Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on the exchange or in the OTC markets. During the three months ended March 31, 2016 and 2015, Generation had net collections of counterparty cash collateral of \$198 million and \$288 million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.

During the three months ended March 31, 2016 and 2015, Generation had net collections of approximately \$17 million and \$5 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

*ComEd*

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During three months ended March 31, 2016 and 2015, ComEd received a return of approximately \$7 million of cash collateral from PJM and posted \$5 million of cash collateral to PJM, respectively. ComEd's collateral posted with PJM has increased year over year due to higher RPM credit requirements and higher PJM billings. As of March 31, 2016 and 2015, ComEd had approximately \$24 million and \$5 million of cash collateral posted with PJM, respectively.



**Table of Contents****Cash Flows from Investing Activities**

Cash flows used in investing activities for the three months ended March 31, 2016 and 2015 by Registrant were as follows:

	<b>Three Months Ended March 31,</b>	
	<b>2016</b>	<b>2015</b>
Exelon	\$ (8,548)	\$ (1,751)
Generation	(1,204)	(899)
ComEd	(626)	(523)
PECO	(351)	(144)
BGE	(191)	(132)
Pepco	(136)	(113)
DPL	(81)	(61)
ACE	(100)	(53)

	<i>Successor</i> <b>March 24, 2016 to March 31, 2016</b>	<i>Predecessor</i> <b>January 1, 2016 to March 23, 2016</b>	<b>Three Months Ended March 31, 2015</b>
	PHI	\$ (30)	\$ (343)

*Generation*

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technologies. The agreements contain a series of scheduled investment commitments, including in-kind service contributions. There are approximately \$299 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2015 Form 10-K for further details of Generation's equity interests.

Capital expenditures by Registrant for the three months ended March 31, 2016 and 2015 and projected amounts for the full year 2016 are as follows:

	<b>Projected Full Year 2016<sup>(a)</sup></b>	<b>Three Months Ended March 31,</b>	
		<b>2016</b>	<b>2015</b>
Exelon	\$ 9,375	\$ 2,202	\$ 1,784
Generation <sup>(b)</sup>	3,600	1,125	937
ComEd <sup>(c)</sup>	2,525	639	530
PECO	675	195	148
BGE	850	176	136
Pepco	725	109	119
DPL	350	81	68
ACE	325	101	54
Other <sup>(d)</sup>	150	38	38

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	Projected Full Year 2016 <sup>(a)</sup>	Successor	Predecessor	
		March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015
PHI	\$ 1,400	\$ 29	\$ 273	\$ 246

- (a) Total projected capital expenditures do not include adjustments for non-cash activity.
- (b) Generation's capital expenditures for the projected full year 2016 includes nuclear fuel (NE fleet at 100%) of \$1.1 billion and growth expenditures of \$1.4 billion.
- (c) The 2016 projections include approximately \$623 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately \$2.6 billion over a ten year period, through 2022, to modernize and storm-harden its distribution system and to implement smart grid technology.
- (d) Other primarily consists of corporate operations, BSC and PHISCO.
- Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

*Generation*

Approximately 31% and 15% of the projected 2016 capital expenditures at Generation are for the acquisition of nuclear fuel and the construction of new natural gas electric generation plants, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

*ComEd, PECO, BGE, Pepco, DPL and ACE*

Approximately 86%, 96%, 97%, 93%, 91% and 92% of the projected 2016 capital expenditures at ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and the Utility Registrants construction commitments under PJM's RTEP. In addition to capital expenditures for continuing projects, ComEd's total expenditures include smart grid/smart meter technology required under EIMA and for PECO, BGE, Pepco, DPL, and ACE capital expenditures related to their respective smart meter program.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2016 capital expenditures above reflect capital spending for remediation to be completed through 2017. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2016.

The Utility Registrants anticipate that they will fund their capital expenditures with a combination of internally generated funds and borrowings and additional capital contributions from parent, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

**Table of Contents****Cash Flows from Financing Activities**

Cash flows provided by (used in) financing activities for the three months ended March 31, 2016 and 2015 by Registrant were as follows:

	Three Months Ended March 31,	
	2016	2015
Exelon	\$ 1,533	\$ 208
Generation	368	(186)
ComEd	296	314
PECO	(69)	(6)
BGE	(86)	(172)
Pepco	(103)	200
DPL	(68)	7
ACE	(27)	(6)

	<i>Successor</i>	<i>Predecessor</i>	
	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015
PHI	\$ (181)	\$ 372	\$ 205
<i>Debt</i>			

See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

**Dividends**

Cash dividend payments and distributions during the three months ended March 31, 2016 and 2015 by Registrant were as follows:

	Three Months Ended March 31,	
	2016	2015
Exelon	\$ 287	\$ 269
Generation	55	1,356
ComEd	91	75
PECO	69	70
BGE <sup>(a)</sup>	48	39
Pepco	39	
DPL	38	62
ACE	11	12

	<i>Successor</i>	<i>Predecessor</i>	
	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015
PHI	\$ 108	\$	\$ 68

(a) Includes dividends paid on BGE's preference stock.

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Quarterly dividends declared by the Exelon Board of Directors during the three months ended March 31, 2016 and for the second quarter of 2016 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share <sup>(a)</sup>
First Quarter 2016	January 26, 2016	February 12, 2016	March 10, 2016	\$ 0.310
Second Quarter 2016	April 26, 2016	May 13, 2016	June 10, 2016	\$ 0.318

(a) Exelon's Board of Directors approved a revised dividend policy. The approved policy would raise the dividend 2.5% each year for the next three years, beginning with the June 2016 dividend. The Board will take formal action to declare the next dividend in the second quarter of 2016.

*Short-Term Borrowings*

Short-term borrowings incurred (repaid) during the three months ended March 31, 2016 and 2015 by Registrant were as follows:

	Three Months Ended March 31,	
	2016	2015
Exelon	\$ 1,647	\$ (141)
Generation	1,377	(1)
ComEd	349	(21)
BGE	(60)	(120)
Pepco	(64)	(104)
DPL	(30)	69
ACE	(5)	16

	Successor	Predecessor	
	March 24, 2016 to March 31, 2016	January 1, 2016 to March 23, 2016	Three Months Ended March 31, 2015
PHI	\$ (20)	\$ 379	\$ 74

*Contributions from Parent/Member*

Contributions received from Parent for the three months ended March 31, 2016 and 2015 by Registrant were as follows:

	Three Months Ended March 31,	
	2016	2015
Generation	\$ 44	\$
ComEd	39 <sup>(a)</sup>	14 <sup>(a)</sup>
BGE	21 <sup>(a)</sup>	
Pepco		112 <sup>(b)</sup>

(a) Contribution paid by Exelon.

(b) Contribution paid by PHI.

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

credit.

*Other*

For the three months ended March 31, 2016, other financing activities primarily consist of debt issuance costs. See Note 10 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

**Table of Contents****Credit Matters**

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include \$9.9 billion in aggregate total commitments of which \$8.3 billion was available as of March 31, 2016, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper market during the first quarter of 2016 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A. RISK FACTORS of the Exelon 2015 Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of March 31, 2016, it would have been required to provide incremental collateral of \$1.9 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of \$4.2 billion.

The following table presents collateral held by each utility registrant at March 31, 2016 under PJM's credit policy, incremental collateral required in the event each utility registrant lost its investment grade credit rating at March 31, 2016 and available credit facility capacity prior to any incremental collateral at March 31, 2016:

	PJM Credit Policy Collateral	Incremental Collateral Required	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	\$ 24	\$ 17	\$ 998
PECO	2	22	599
BGE	4	28	600
Pepco	2		250
DPL	3	9	250
ACE			250

**Exelon Credit Facilities**

Exelon, ComEd, and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the Exelon intercompany money pool. PHI meets its short-term liquidity requirements primarily through the issuance of commercial paper, short-term notes and the Exelon intercompany money pool. Pepco, DPL and ACE meet their short-term liquidity requirements primarily through the issuance of commercial paper and short-term notes. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and the issuance of letters of credit.

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The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at March 31, 2016:

**Commercial Paper Programs**

Commercial Paper Issuer	Maximum Program Size <sup>(a)(b)(c)</sup>	Outstanding Commercial Paper at March 31, 2016	Average Interest Rate on Commercial Paper Borrowings for the Three Months Ended March 31, 2016
Exelon Corporate	\$ 500	\$	0.70%
Generation	5,300	1,378	0.99%
ComEd	1,000	643	0.79%
PECO	600		%
BGE	600	150	0.79%
PHI Corporate	875	442	1.07%
Pepco	500		0.68%
DPL	500	75	0.69%
ACE	350		0.65%

(a) Excludes \$425 million bilateral credit facilities that do not back Generation's commercial paper program.

(b) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of \$50 million, \$34 million, \$34 million and \$5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 14, 2016. These facilities are solely utilized to issue letters of credit. As of March 31, 2016, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled \$7 million, \$14 million, \$21 million and \$2 million, respectively.

(c) Subject to available borrowing capacity under the credit facility.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its commercial paper outstanding does not reduce available capacity under a Registrant's credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility. At March 31, 2016, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

**Credit Agreements**

Borrower	Facility Type	Aggregate Bank Commitment <sup>(a)(b)</sup>	Facility Draws	Outstanding Letters of Credit	Available Capacity at March 31, 2016	
					Actual	To Support Additional Commercial Paper <sup>(c)</sup>
Exelon Corporate	Syndicated Revolver	\$ 500	\$	\$ 26	\$ 474	\$ 474
Generation <sup>(d)</sup>	Syndicated Revolver	5,300		1,164	4,136	2,758
Generation	Bilaterals	425	80	329	16	
ComEd	Syndicated Revolver	1,000		2	998	355
PECO	Syndicated Revolver	600		1	599	599
BGE	Syndicated Revolver	600			600	450
PHI Corporate	Syndicated Revolver	750		1	749	307
Pepco	Syndicated Revolver	250			250	250
DPL	Syndicated Revolver	250			250	175
ACE	Syndicated Revolver	250			250	250



- (a) Excludes \$123 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 14, 2016. These facilities are solely utilized to issue letters of credit. As of March 31, 2016, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled \$7 million, \$14 million, \$21 million and \$2 million, respectively.

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- (b) Excludes nonrecourse debt letters of credit, see Note 14 Debt and Credit Agreements in the Exelon 2015 Form 10-K for further information on Continental Wind nonrecourse debt.
- (c) Excludes \$425 million bilateral credit facilities that do not back Generation's commercial paper program.
- (d) Excludes ExGen Texas Power Financing's \$18 million of borrowed debt on its revolving credit facility.
- As of March 31, 2016, there was \$80 million of borrowings under Generation's bilateral credit facilities.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Borrowings under PHI Corporate's, Pepco's, DPL's, and ACE's revolving credit agreements bear interest at a rate based upon either the greater of the prevailing prime rate, the federal funds effective rate plus 50 basis points or the one month LIBOR plus 100.0 basis points, or the prevailing Eurodollar rate, plus a margin based upon the particular Registrant's credit rating. PHI Corporate, Pepco, DPL and ACE have margins of 22.5, 17.5, 17.5, and 17.5 basis points.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO, and BGE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the three months ended March 31, 2016:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At March 31, 2016, the interest coverage ratios at the Exelon, Generation, ComEd, PECO and BGE were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	10.73	12.47	7.13	8.60	10.43

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of \$100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility.

The revolving credit agreement for PHI, Pepco, DPL and ACE requires that each borrowing company maintain a maximum total indebtedness to total capitalization ratio. The following table summarizes the maximum thresholds reflected in the credit agreements for the three months ended March 31, 2016:

	PHI	Pepco	DPL	ACE
Credit agreement threshold	0.65 to 1	0.65 to 1	0.65 to 1	0.65 to 1

At March 31, 2016, the total indebtedness to total capitalization ratios at PHI, Pepco, DPL and ACE were as follows:

	PHI	Pepco	DPL	ACE
Total indebtedness to total capitalization ratio	0.51	0.52	0.53	0.52

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PHI, Pepco, DPL and ACE maintain an unsecured syndicated credit facility to provide for their respective liquidity needs, including obtaining letters of credit, borrowing for general corporate purposes and supporting their commercial paper programs. The termination date of this credit facility is currently August 1, 2018. In order for PHI, Pepco, DPL or ACE to use its facility, certain representations and warranties must be true and correct, and the borrower must be in compliance with specified financial and other covenants, including (i) the requirement that each borrowing company maintain a ratio of total indebtedness to total capitalization of 65% or less, computed in accordance with the terms of the credit agreement, which calculation excludes from the definition of total indebtedness certain trust preferred securities and deferrable interest subordinated debt (not to exceed 15% of total capitalization), (ii) with certain exceptions, a restriction on sales or other dispositions of assets, and (iii) a restriction on the incurrence of liens on the assets of a borrower or any of its significant subsidiaries other than permitted liens. The credit agreement contains certain covenants and other customary agreements and requirements that, if not complied with, could result in an event of default and the acceleration of repayment obligations of one or more of the borrowers thereunder. PHI, Pepco, DPL and ACE were in compliance with all covenants under their facilities at March 31, 2016.

The absence of a material adverse change in Exelon's or PHI's business, property, results of operations or financial condition is not a condition to the availability of credit under the credit agreement. The credit agreement does not include any rating triggers.

**Security Ratings**

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance, which could include the posting of collateral. See Note 9 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

**Intercompany Money Pool**

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate intercompany money pools. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2016, are presented in the following table:

Exelon Intercompany Money Pool	During the Three Months Ended March 31, 2016		As of March 31, 2016
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Contributed (borrowed)			
Exelon Corporate	\$ 1,534	n/a	\$ 165
Generation		1,292	(63)
PECO	285		160
BSC		387	(325)
PHI Corporate <sup>(a)</sup>	n/a		
PCI <sup>(a)</sup>	63		63

(a) As a result of the merger, PHI Corporate and PCI began to participate in the Exelon Intercompany Money Pool effective March 24, 2016.

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PHI Intercompany Money Pool	During the Three Months Ended March 31, 2016		As of March 31, 2016
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Contributed (borrowed)			
PHI Corporate	\$ 129	n/a	\$ 129
Pepco			
DPL			
ACE			
PHISCO		151	(129)

**Investments in Nuclear Decommissioning Trust Funds**

Exelon, Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 12 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

**Shelf Registration Statements**

Exelon, Generation, ComEd, PECO and BGE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. PHI, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2016. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

**Regulatory Authorizations**

Generation, ComEd, PECO, BGE, Pepco, DPL and Ace are required to obtain short-term and long-term financing authority from Federal and State Commissions as follows:

	Short-term Financing Authority <sup>(a)</sup>			Long-term Financing Authority	
	Commission	Expiration Date	Amount (in millions)	Commission	Amount (in millions)
ComEd <sup>(b)</sup>	FERC	December 31, 2017	\$ 2,500	ICC	\$ 1,795
PECO	FERC	December 31, 2017	1,500	PAPUC	1,900
BGE	FERC	December 31, 2017	700	MDPSC	1,400
Pepco	FERC	June 30, 2016	500	MDPSC / DCPSC	550
DPL	FERC	June 30, 2016	500	MDPSC / DPSC	300
ACE	NJPU	January 1, 2018	350	NJBPU	300

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

(b) ComEd had \$442 million available in long-term debt refinancing authority and \$1,353 million available in new money long term debt financing authority from the ICC as of March 31, 2016.

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**Contractual Obligations and Off-Balance Sheet Arrangements**

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 23 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in the Exelon 2015 Form 10-K and Note 16 Commitments and Contingencies of the PHI 2015 Form 10-K for discussion of the Registrants' commitments.

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO, and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrants' contractual obligations and off-balance sheet arrangements, see Management's Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Off-Balance Sheet Arrangements in the Exelon 2015 Form 10-K and Management's Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Commercial Commitments and Management's Discussion and Analysis of Financial Condition and Results of Operations Guarantees, Indemnifications and Off-Balance Sheet Arrangements in the PHI 2015 Form 10-K.

**Table of Contents****Item 3. Quantitative and Qualitative Disclosures about Market Risk**

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2015 Annual Report on Form 10-K incorporated herein by reference.

**Commodity Price Risk (All Registrants)**

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

**Generation**

**Normal Operations and Hedging Activities.** Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of the Utility Registrants' retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including forwards, futures, swaps and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2016 through 2018.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Exelon's hedging program involves the hedging of commodity risk for Exelon's expected generation, typically on a ratable basis over a three-year period. As of March 31, 2016, the proportion of expected generation hedged is 96%-99%, 69%-72% and 37%-40% 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.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-proprietary trading portfolio associated with a \$5 reduction in the annual average around-the-clock energy price based on March 31, 2016 market conditions and hedged position would be a decrease in pre-tax net income of approximately \$5 million, \$315 million and \$630 million, respectively, for 2016, 2017 and 2018. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

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**Proprietary Trading Activities.** 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 portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,220 GWhs and 1,808 GWhs for the three months ended March 31, 2016 and 2015, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Proprietary trading portfolio activity for the three months ended March 31, 2016 resulted in pre-tax gains of \$3 million due to net mark-to-market gains of \$3 million and immaterial realized gains. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period and a one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged \$0.3 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total Revenue net of purchase power and fuel expense from continuing operations for the three months ended March 31, 2016 of \$2,297 million.

**Fuel Procurement.** Generation procures natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel assemblies are obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2016 through 2020 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial positions. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding uranium and coal supply agreement matters.

**ComEd**

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

**PECO**

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 of the Combined Notes to Consolidated Financial Statements. PECO has certain full requirements contracts which are considered derivatives and qualify for the normal purchases and normal sales scope

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exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

***BGE***

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result, are accounted for on an accrual basis of accounting. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

***Pepco***

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.

Pepco does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.



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***DPL***

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the DPSC. The SOS rates charged recover DPL's wholesale power supply costs and include 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. DPL's price risk related to electric supply procurement is limited. DPL locks in fixed prices for all of its SOS requirements through full requirements contracts. 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 a GCR mechanism approved by the DPSC. 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.

DPL does not enter into derivatives for speculative or proprietary trading purposes. See Note 9 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

***ACE***

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE's wholesale power supply costs. ACE does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE's price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. 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.

ACE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 9 – Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

***Trading and Non-Trading Marketing Activities.*** The following detailed presentation of Exelon's, Generation's, ComEd's, PHI's and DPL's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

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The following table provides detail on changes in Exelon's, Generation's, ComEd's, PHI's and DPL's commodity mark-to-market net asset or liability balance sheet position from December 31, 2015 to March 31, 2016. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of March 31, 2016 and December 31, 2015.

	Generation	ComEd	DPL <sup>(a)</sup>	Exelon <sup>(b)</sup>
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 <sup>(c)</sup>	\$ 1,753	\$ (247)	\$	\$ 1,506
Total change in fair value during 2016 of contracts recorded in results of operations	159			159
Reclassification to realized at settlement of contracts recorded in results of operations	(47)			(47)
Changes in fair value energy derivative <sup>(d)</sup>		(18)	(1)	(19)
Changes in allocated collateral	(195)		1	(194)
Changes in net option premium paid/(received)	(17)			(17)
Option premium amortization	9			9
Other balance sheet reclassifications <sup>(e)</sup>	(22)			(22)
Total mark-to-market energy contract net assets (liabilities) at March 31, 2016 <sup>(c)</sup>	\$ 1,640	\$ (265)	\$	\$ 1,375

- (a) As of March 31, 2016 and December 31, 2015, PHI's and DPL's mark-to-market derivative liability was fully collateralized resulting in a zero balance. For the predecessor period of January 1, 2016 to March 23, 2016, PHI recorded a \$1 million increase in fair value and \$1 million increase in allocated collateral related to the exchange-traded futures.
- (b) As a result of the merger, Exelon amounts include PHI and DPL activity from March 24, 2016 to March 31, 2016. For the successor period of March 24, 2016 to March 31, 2016, there was no change in fair value and allocated collateral related to the exchange-traded futures.
- (c) Amounts are shown net of collateral paid to and received from counterparties.
- (d) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of March 31, 2016, ComEd recorded a \$265 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the three months ended March 31, 2016, ComEd also recorded \$25 million of decreases in fair value and realized losses due to settlements of \$7 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of March 31, 2016, DPL recorded a \$1 million regulatory asset related to its mark-to-market derivative liabilities.
- (e) Other balance sheet reclassifications include derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums.

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**Fair Values.** The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 8 Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

**Exelon**

	Maturities Within					2021 and Beyond	Total Fair Value
	2016	2017	2018	2019	2020		
Normal Operations, Commodity derivative contracts <sup>(a)(b)</sup> :							
Actively quoted prices (Level 1)	\$ (76)	\$ 15	\$ (22)	\$ (20)	\$ (6)	\$	\$ (109)
Prices provided by external sources (Level 2)	529	191	(9)	(10)	1		702
Prices based on model or other valuation methods (Level 3) <sup>(c)</sup>	424	337	154	(21)	(21)	(91)	782
<b>Total</b>	<b>\$ 877</b>	<b>\$ 543</b>	<b>\$ 123</b>	<b>\$ (51)</b>	<b>\$ (26)</b>	<b>\$ (91)</b>	<b>\$ 1,375</b>

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$1,039 million at March 31, 2016.

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

**Generation**

	Maturities Within					2021 and Beyond	Total Fair Value
	2016	2017	2018	2019	2020		
Normal Operations, Commodity derivative contracts <sup>(a)(b)</sup> :							
Actively quoted prices (Level 1)	\$ (76)	\$ 15	\$ (22)	\$ (20)	\$ (6)	\$	\$ (109)
Prices provided by external sources (Level 2)	529	191	(9)	(10)	1		702
Prices based on model or other valuation methods (Level 3)	444	361	177	2	2	61	1,047
<b>Total</b>	<b>\$ 897</b>	<b>\$ 567</b>	<b>\$ 146</b>	<b>\$ (28)</b>	<b>\$ (3)</b>	<b>\$ 61</b>	<b>\$ 1,640</b>

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$1,039 million at March 31, 2016.

**Table of Contents****ComEd**

	Maturities Within					2021 and Beyond	Total Fair Value
	2016	2017	2018	2019	2020		
Prices based on model or other valuation methods (Level 3) <sup>(a)</sup>	\$ (20)	\$ (24)	\$ (23)	\$ (23)	\$ (23)	\$ (152)	\$ (265)

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

**Credit Risk, Collateral and Contingent Related Features (All Registrants)**

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral and contingent related features.

**Generation**

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2016. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of \$19 million, \$37 million, \$35 million, \$36 million, \$11 million, and \$8 million as of March 31, 2016, respectively. See Note 26 Related Party Transactions of the Exelon 2015 Form 10-K for additional information.

Rating as of March 31, 2016	Total Exposure		Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
	Before Credit Collateral	Credit Collateral <sup>(a)</sup>			
Investment grade	\$ 1,276	\$ 58	\$ 1,218	1	\$ 436
Non-investment grade	71	32	39		
No external ratings					
Internally rated investment grade	516	1	515		
Internally rated non-investment grade	101	4	97		
Total	\$ 1,964	\$ 95	\$ 1,869	1	\$ 436

Rating as of March 31, 2016	Maturity of Credit Risk Exposure			Total Exposure Before Credit Collateral
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	

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Investment grade	\$ 910	\$ 347	\$ 19	\$ 1,276
Non-investment grade	59	12		71
No external ratings				
Internally rated investment grade	433	54	29	516
Internally rated non-investment grade	83	18		101
Total	\$ 1,485	\$ 431	\$ 48	\$ 1,964

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	As of March 31, 2016
<b>Net Credit Exposure by Type of Counterparty</b>	
Financial institutions	\$ 116
Investor-owned utilities, marketers, power producers	781
Energy cooperatives and municipalities	909
Other	63
<b>Total</b>	<b>\$ 1,869</b>

(a) As of March 31, 2016, credit collateral held from counterparties where Generation had credit exposure included \$8 million of cash and \$87 million of letters of credit.

***ComEd, PECO and BGE***

There have been no significant changes or additions to ComEd's, PECO's, or BGE's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2015 Annual Report on Form 10-K.

See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

***PHI, Pepco, DPL and ACE***

There have been no significant changes or additions to PHI's, Pepco's, DPL's or ACE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of PHI's 2015 Annual Report on Form 10-K.

See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

***Collateral (All Registrants)******Generation***

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, natural gas and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above or fall below contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities, which serve as liquidity sources to fund collateral requirements. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities for additional information.



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As of March 31, 2016, Generation had cash collateral of \$1,063 million posted and cash collateral held of \$16 million for external counterparties with derivative positions, of which \$1,039 million and \$7 million in net cash collateral deposits were offset against energy derivative and interest rate and foreign exchange derivative related to underlying energy contracts, respectively. As of March 31, 2016, \$1 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as of the balance sheet date there were no positions to offset. See Note 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

*ComEd*

As of March 31, 2016, ComEd held no collateral from suppliers in association with energy procurement contracts and held approximately \$19 million in the form of cash and letters of credit for renewable energy contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 Regulatory Matters of the 2015 Exelon Form 10-K for additional information.

*PECO*

As of March 31, 2016, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

*BGE*

BGE is not required to post collateral under its electric supply contracts. As of March 31, 2016, BGE was not required to post collateral under its natural gas procurement contracts nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

*Pepco*

Pepco is not required to post collateral under its energy procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

*DPL*

DPL is not required to post collateral under its energy procurement contracts. As of March 31, 2016, DPL was required to post collateral of \$1 million under its natural gas procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

*ACE*

ACE is not required to post collateral under its energy procurement contracts. See Note 9 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

***RTOs and ISOs (All Registrants)***

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity



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is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may, under certain circumstances, require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

***Exchange Traded Transactions (Exelon, Generation, PHI and DPL)***

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. DPL enters into commodity transactions on ICE. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

***Long-Term Leases (Exelon)***

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 6 – Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

***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 Exelon registrants may also 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 March 31, 2016, Exelon had \$800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had \$1,287 million and \$687 million of notional amounts of floating-to-fixed hedges outstanding, respectively. 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 approximately a \$1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 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.

***Equity Price Risk (Exelon and Generation)***

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of March 31, 2016, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a \$470 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and

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equity prices. See ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

**Item 4. Controls and Procedures**

During the first quarter of 2016, each of Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's management, including its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon's management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC's rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of March 31, 2016, the principal executive officer and principal financial officer of each of Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. On March 23, 2016, the merger between Exelon and PHI closed. There have been no changes in internal control over financial reporting that occurred during the first quarter of 2016, other than changes resulting from the PHI Merger, that have materially affected, or are reasonably likely to materially affect, any of Exelon's, Generation's, ComEd's, PECO's, BGE's, PHI's, Pepco's, DPL's and ACE's internal control over financial reporting. See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for further information regarding the PHI acquisition. Exelon's management expects that the controls over financial reporting associated with PHI, Pepco, DPL and ACE from the date of the merger forward will be covered in the year-end assessment.

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**PART II OTHER INFORMATION**

**Item 1 Legal Proceedings**

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2015 Form 10-K (b) ITEM 3. LEGAL PROCEEDINGS of PHI's 2015 Form 10-K and (c) Notes 5 Regulatory Matters and 18 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

**Item 1A Risk Factors  
Risks Related to Exelon**

Exclusive of the *Risks Related to the Pending Merger with PHI* described in Exelon's 2015 Form 10-K in ITEM 1A. RISK FACTORS, Exelon is, and will continue to be, subject to the risks described in Exelon's and PHI's 2015 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 of the Combined Notes to Consolidated Financial Statements in Exelon's 2015 Form 10-K and Note 16 of the Notes to Consolidated Financial Statements in PHI's 2015 Form 10-K. As a result of the merger with PHI that closed on March 23, 2016 Exelon is subject to additional risks related to the merger as described below.

**Risks Related to the PHI Merger**

**The merger may not achieve its anticipated results, and Exelon may be unable to integrate the operations of PHI in the manner expected.**

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon's businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. Exelon may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs and could adversely affect Exelon's future business, financial condition, operating results and prospects.

**The merger may not be accretive to earnings and may cause dilution to Exelon's earnings per share, which may negatively affect the market price of Exelon's common stock.**

The timing and amount of accretion expected could be significantly adversely affected by a number of uncertainties, including market conditions, risks related to Exelon's businesses and whether the business of PHI is integrated in an efficient and effective manner. Exelon also could encounter additional transaction and integration-related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.

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**Exelon may incur unexpected transaction fees and merger-related costs in connection with the merger.**

Exelon expects to incur a number of non-recurring expenses associated with completing the merger, as well as expenses related to combining the operations of the two companies. Exelon may incur additional unanticipated costs in the integration of the businesses of Exelon and PHI. Although Exelon expects that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger-related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

**Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the PHI Merger.**

As a result of the process to obtain regulatory approvals required for the PHI Merger, Exelon is committed to various programs, contributions and investments in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties, or additional costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon's financial position and operating results.

**Item 4 Mine Safety Disclosures  
Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE**

Not applicable to the Registrants.

**Item 6 Exhibits**

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

**Exhibit**

<b>No.</b>	<b>Description</b>
2.1	Letter Agreement, dated March 7, 2016, among Pepco Holdings, Inc., Exelon Corporation and Purple Acquisition Corp. (File No. 001-31403, Form 8-K dated March 7, 2016, Exhibit 2)
3.1	Exelon Corporation Amended and Restated Bylaws, as amended on April 26, 2016 (File No. 001-16169, Form 8-K dated April 29, 2016, Exhibit 4.1)
4.1	Third Supplemental Indenture, dated as of April 7, 2016, among Exelon Corporation and The Bank of New York Mellon Trust Company, N.A., as trustee (File No. 001-16169, Form 8-K dated April 7, 2016, Exhibit 4.2)
10.1	First Amendment to Loan Agreement, by and between Pepco Holdings LLC and The Bank of Nova Scotia, as administrative agent and lender, dated March 28, 2016 (File No. 001-31403, Form 8-K dated March 28, 2016, Exhibit 2)
10.2	Amendment To The Pepco Holdings, Inc. Second Revised And Restated Executive And Director Deferred Compensation Plan
10.3	First Amendment To The Pepco Holdings, Inc. 2014 Management Employee Severance Plan
10.4	First Amendment To The Pepco Holdings, Inc. Amended And Restated Change-In-Control/Severance Plan For Certain Executive Employees
10.5	Omnibus Amendment Pepco Holdings, Inc. Supplemental Executive Retirement Plans

10.6 2016 Amendment to the Pepco Holdings, Inc. Retirement Plan

**Table of Contents****Exhibit**

<b>No.</b>	<b>Description</b>
18.1	Letter from PricewaterhouseCoopers LLP to the Board of Directors of Pepco Holdings LLC dated May 10, 2016 regarding a change in accounting principles
18.2	Letter from PricewaterhouseCoopers LLP to the Board of Directors of Atlantic City Electric Company dated May 10, 2016 regarding a change in accounting principles
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation
Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016 filed by the following officers for the following companies:	
31-1	Filed by Christopher M. Crane for Exelon Corporation
31-2	Filed by Jonathan W. Thayer for Exelon Corporation
31-3	Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
31-4	Filed by Bryan P. Wright for Exelon Generation Company, LLC
31-5	Filed by Anne R. Pramaggiore for Commonwealth Edison Company
31-6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31-7	Filed by Craig L. Adams for PECO Energy Company
31-8	Filed by Phillip S. Barnett for PECO Energy Company
31-9	Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
31-10	Filed by David M. Vahos for Baltimore Gas and Electric Company
31-11	Filed by David M. Velazquez for Pepco Holdings LLC
31-12	Filed by Donna J. Kinzel for Pepco Holdings LLC
31-13	Filed by David M. Velazquez for Potomac Electric Power Company
31-14	Filed by Donna J. Kinzel for Potomac Electric Power Company
31-15	Filed by David M. Velazquez for Delmarva Power & Light Company
31-16	Filed by Donna J. Kinzel for Delmarva Power & Light Company
31-17	Filed by David M. Velazquez for Atlantic City Electric Company
31-18	Filed by Donna J. Kinzel for Atlantic City Electric Company

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Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2016 filed by the following officers for the following companies:

- 32-1 Filed by Christopher M. Crane for Exelon Corporation
- 32-2 Filed by Jonathan W. Thayer for Exelon Corporation
- 32-3 Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
- 32-4 Filed by Bryan P. Wright for Exelon Generation Company, LLC
- 32-5 Filed by Anne R. Pramaggiore for Commonwealth Edison Company
- 32-6 Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
- 32-7 Filed by Craig L. Adams for PECO Energy Company
- 32-8 Filed by Phillip S. Barnett for PECO Energy Company
- 32-9 Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
- 32-10 Filed by David M. Vahos for Baltimore Gas and Electric Company
- 32-11 Filed by David M. Velazquez for Pepco Holdings LLC
- 32-12 Filed by Donna J. Kinzel for Pepco Holdings LLC
- 32-13 Filed by David M. Velazquez for Potomac Electric Power Company
- 32-14 Filed by Donna J. Kinzel for Potomac Electric Power Company
- 32-15 Filed by David M. Velazquez for Delmarva Power & Light Company
- 32-16 Filed by Donna J. Kinzel for Delmarva Power & Light Company
- 32-17 Filed by David M. Velazquez for Atlantic City Electric Company
- 32-18 Filed by Donna J. Kinzel for Atlantic City Electric Company

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**SIGNATURES**

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**EXELON CORPORATION**

/s/ CHRISTOPHER M. CRANE  
Christopher M. Crane  
President and Chief Executive Officer

(Principal Executive Officer) and Director

/s/ JONATHAN W. THAYER  
Jonathan W. Thayer  
Senior Executive Vice President and Chief Financial

Officer  
  
(Principal Financial Officer)

/s/ DUANE M. DESPARTE  
Duane M. DesParte  
Senior Vice President and Corporate Controller

(Principal Accounting Officer)

May 10, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**EXELON GENERATION COMPANY, LLC**

/s/ KENNETH W. CORNEW  
Kenneth W. Cornew  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ BRYAN P. WRIGHT  
Bryan P. Wright  
Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

/s/ MATTHEW N. BAUER  
Matthew N. Bauer  
Vice President and Controller

(Principal Accounting Officer)

May 10, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**COMMONWEALTH EDISON COMPANY**

/s/ ANNE R. PRAMAGGIORE  
Anne R. Pramaggiore

/s/ JOSEPH R. TRPIK, JR.  
Joseph R. Trpik, Jr.



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President and Chief Executive Officer

Senior Vice President, Chief Financial Officer and

(Principal Executive Officer)

Treasurer

(Principal Financial Officer)

/s/ GERALD J. KOZEL

Gerald J. Kozel

Vice President and Controller

(Principal Accounting Officer)

May 10, 2016

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**PECO ENERGY COMPANY**

/s/ CRAIG L. ADAMS  
Craig L. Adams  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ SCOTT A. BAILEY  
Scott A. Bailey  
Vice President and Controller

(Principal Accounting Officer)

May 10, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**BALTIMORE GAS AND ELECTRIC COMPANY**

/s/ CALVIN G. BUTLER, JR.  
Calvin G. Butler, Jr.  
Chief Executive Officer

(Principal Executive Officer)

/s/ ANDREW W. HOLMES  
Andrew W. Holmes  
Vice President and Controller

(Principal Accounting Officer)

May 10, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**PEPCO HOLDINGS LLC**

/s/ DAVID M. VELAZQUEZ  
David M. Velazquez

/s/ DONNA J. KINZEL  
Donna J. Kinzel

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President and Chief Executive Officer

Senior Vice President, Chief Financial Officer and

(Principal Executive Officer)

Treasurer

(Principal Financial Officer)

/s/ ROBERT M. AIKEN

Robert M. Aiken

Vice President and Controller

(Principal Accounting Officer)

May 10, 2016

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Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**POTOMAC ELECTRIC POWER COMPANY**

/s/ DAVID M. VELAZQUEZ  
David M. Velazquez  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ ROBERT M. AIKEN  
Robert M. Aiken  
Vice President and Controller

(Principal Accounting Officer)

/s/ DONNA J. KINZEL  
Donna J. Kinzel  
Senior Vice President, Chief Financial Officer and

Treasurer

(Principal Financial Officer)

May 10, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**DELMARVA POWER & LIGHT COMPANY**

/s/ DAVID M. VELAZQUEZ  
David M. Velazquez  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ ROBERT M. AIKEN  
Robert M. Aiken  
Vice President and Controller

(Principal Accounting Officer)

/s/ DONNA J. KINZEL  
Donna J. Kinzel  
Senior Vice President, Chief Financial Officer and

Treasurer

(Principal Financial Officer)

May 10, 2016

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

**ATLANTIC CITY ELECTRIC COMPANY**

/s/ DAVID M. VELAZQUEZ  
David M. Velazquez

/s/ DONNA J. KINZEL  
Donna J. Kinzel

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President and Chief Executive Officer

Senior Vice President, Chief Financial Officer and

(Principal Executive Officer)

Treasurer

(Principal Financial Officer)

/s/ ROBERT M. AIKEN

Robert M. Aiken

Vice President and Controller

(Principal Accounting Officer)

May 10, 2016