EXELON CORP
Form 10-Q
October 26, 2016
Table of Contents

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

or

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

Commission File Number	**Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number**	**IRS Employer Identification Number**
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028	36-0938600

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

Table of Contents

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

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

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

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

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

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

Exelon Corporation Common Stock, without par value	923,270,314
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,143
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	not applicable
Potomac Electric Power Company Common Stock, $.01 par value	100
Delmarva Power & Light Company Common Stock, $2.25 par value	1,000
Atlantic City Electric Company Common Stock, $3.00 par value	8,546,017

Table of Contents

TABLE OF CONTENTS

Table of Contents

Table of Contents

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
BSC	Exelon Business Services Company, LLC
PHISCO	PHI Service Company
Exelon Corporate	Exelon in its corporate capacity as a holding company
PHI Corporate	PHI in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Antelope Valley	Antelope Valley Solar Ranch One
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, collectively
Utility Registrants	ComEd, PECO, BGE, Pepco, DPL and ACE, collectively
Legacy PHI	PHI, Pepco, DPL and ACE, collectively
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc.
Other Terms and Abbreviations	
Note of the Exelon 2015 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon s 2015 Annual Report on Form 10-K
Note of the PHI 2015 Form 10-K	Reference to specific Note to Consolidated Financial Statements within Legacy PHI s 2015 Annual Report on Form 10-K
1998 restructuring settlement	PECO s 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
ASC	Accounting Standards Codification
BGS	Basic Generation Service (the supply of electricity by ACE to retail customers in New Jersey who have not elected to purchase electricity from a competitive supplier)
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
Contract EDCs	Pepco, DPL and BGE, the Maryland utilities required by the MDPSC to enter into a contract for new generation
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
CTC	Competitive Transition Charge
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DCPSC	District of Columbia Public Service Commission
DC PLUG	District of Columbia Power Line Undergrounding
Default Electricity Supply	The supply of electricity by PHI s electric utility subsidiaries at regulated rates to retail customers who do not elect to purchase electricity from a competitive supplier, and which, depending on the jurisdiction, is also known as Standard Offer Service or BGS
Default Electricity Supply Revenue	Revenue primarily from Default Electricity Supply
DOE	United States Department of Energy
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

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

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

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

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
ROE	Return on equity
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RSSA	Reliability Support Services Agreement
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant from DOE
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOCAs	Standard Offer Capacity Agreements required to be entered into by ACE pursuant to a New Jersey law enacted to promote the construction of qualified electric generation facilities in New Jersey
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
Transition Bond Charge	Revenue ACE receives, and pays to ACE Funding, to fund the principal and interest payments on Transition Bonds and related taxes, expenses and fees
Transition Bonds	Transition Bonds issued by ACE Funding
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

Table of Contents

FILING FORMAT

This combined Form 10-Q is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company, and Atlantic City Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon s 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 23; (2) PHI s 2015 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 16; (3) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 18; and (4) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

12

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

13

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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

(a) Exelon s consolidated assets include $8,514 million and $8,268 million at September 30, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $3,438 million and $3,264 million at September 30, 2016 and December 31, 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Preference Stock	Total Shareholders Equity
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294
Net income				930		18	8	956
Long-term incentive plan activity	2,422	61						61
Employee stock purchase plan issuances	924	36						36
Tax benefit on stock compensation		(17)						(17)
Changes in equity of noncontrolling interests						5		5
Adjustment of contingently redeemable noncontrolling interest due to release of contingency						107		107
Common stock dividends				(877)				(877)
Redemption of preference stock							(193)	(193)
Preference stock dividends							(8)	(8)
Other comprehensive income (loss), net of income taxes					101	(5)		96
Balance, September 30, 2016	958,014	$ 18,756	$ (2,327)	$ 12,121	$ (2,523)	$ 1,433	$	$ 27,460

See the Combined Notes to Consolidated Financial Statements

15

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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

(a) Generation s consolidated assets include $8,415 million and $8,235 million at September 30, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include $3,196 million and $3,135 million at September 30, 2016 and December 31, 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

	Member s Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942
Net income		538		18	556
Changes in equity of noncontrolling interests				5	5
Adjustment of contingently redeemable noncontrolling interests due to release of contingency				107	107
Allocation of tax benefit from member	98				98
Contribution from member	170				170
Distribution to member		(167)			(167)
Other comprehensive income (loss), net of income taxes			7	(5)	2
Balance, September 30, 2016	$ 9,265	$ 3,072	$ (56)	$ 1,432	$ 13,713

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

22

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders Equity
Balance, December 31, 2015	$ 1,588	$ 5,677	$ (1,639)	$ 2,617	$ 8,243
Net income			297		297
Appropriation of retained earnings for future dividends			(297)	297	
Common stock dividends				(275)	(275)
Contribution from parent		188			188
Parent tax matter indemnification		157			157
Balance, September 30, 2016	$ 1,588	$ 6,022	$ (1,639)	$ 2,639	$ 8,610

See the Combined Notes to Consolidated Financial Statements

25

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

30

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

31

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

33

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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

BGE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$ 2,877
Net income		191	191		191
Preference stock dividends		(8)	(8)		(8)
Common stock dividends		(134)	(134)		(134)
Distribution to parent	(7)		(7)		(7)
Contribution from parent	28		28		28
Redemption of preference stock				(190)	(190)
Balance, September 30, 2016	$ 1,388	$ 1,369	$ 2,757	$	$ 2,757

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

37

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

38

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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

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

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PEPCO HOLDINGS LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

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

(a) At March 23, 2016 and December 31, 2015, PHI s (predecessor) shareholders equity included $3,835 million and $3,829 million of other paid-in capital, and $3 million and $3 million of common stock, respectively.
(b) The March 24, 2016, beginning balance differs from the PHI Merger total purchase price by $59 million related to an acquisition accounting adjustment recorded at Exelon Corporate to reflect unitary state income tax consequences of the merger.
(c) Distribution to member includes $235 million of net assets associated with PHI s unregulated business interests and $66 million of cash, each of which were distributed by PHI to Exelon.
(d) The liabilities assumed include $29 million for PHI stock-based compensation awards and $33 million for a merger related obligation, each assumed by PHI from Exelon. See Note 4 Mergers, Acquisitions and Dispositions.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Financial Statements

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

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

See the Combined Notes to Financial Statements

42

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Financial Statements

43

POTOMAC ELECTRIC POWER COMPANY

BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Financial Statements

Table of Contents

POTOMAC ELECTRIC POWER COMPANY

STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2015	$ 1,122	$ 1,118	$ 2,240
Net Income		20	20
Common stock dividends		(125)	(125)
Contribution from parent	187		187
Balance, September 30, 2016	$ 1,309	$ 1,013	$ 2,322

See the Combined Notes to Financial Statements

45

Table of Contents

DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Financial Statements

46

Table of Contents

DELMARVA POWER & LIGHT COMPANY

STATEMENTS OF CASH FLOWS

(Unaudited)

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

See the Combined Notes to Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY

BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Financial Statements

Table of Contents

DELMARVA POWER & LIGHT COMPANY

STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2015	$ 612	$ 625	$ 1,237
Net loss		(16)	(16)
Common stock dividends		(39)	(39)
Contribution from parent	113		113
Balance, September 30, 2016	$ 725	$ 570	$ 1,295

See the Combined Notes to Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

53

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

Table of Contents

ATLANTIC CITY ELECTRIC COMPANY AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

55

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

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Exelon Corporation	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Exelon Generation Company, LLC	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.		.	.	.
Commonwealth Edison Company	.	.	.		.			.	.	.	.		.	.				.	.	.
PECO Energy Company	.	.	.		.			.	.	.	.		.	.	.			.	.	.
Baltimore Gas and Electric Company	.	.	.		.			.	.	.	.		.	.			.	.	.	.
Pepco Holdings LLC	.	.	.	.	.			.	.	.	.		.	.	.	.		.	.	.
Potomac Electric Power Company	.	.	.	.	.			.	.	.	.		.	.				.	.	.
Delmarva Power & Light Company	.	.	.		.			.	.	.	.		.	.				.	.	.
Atlantic City Electric Company	.	.	.		.			.	.	.	.		.	.				.	.	.

1. Significant Accounting Policies (All Registrants)

Description of Business (All Registrants)

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

The energy generation business includes:

Generation: Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Basis of Presentation (All Registrants)

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

For financial statement purposes, beginning on March 24, 2016, disclosures that had solely related to PHI, Pepco, DPL or ACE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are named specifically for their related activities and disclosures.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

ACE Basic Generation Service Recovery Mechanism

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

Classification of Interest on Uncertain Tax Positions

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

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

The accompanying consolidated financial statements as of September 30, 2016 and 2015 and for the three and nine months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrants respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2015 Consolidated Balance Sheets were obtained from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2016. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations.

2. New Accounting Pronouncements (All Registrants)

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Customer s Accounting for Fees Paid in a Cloud Computing Arrangement

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

Amendments to the Consolidation Analysis

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

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

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the transition method that they will use to adopt the guidance. Exelon is considering the impacts of the new guidance on its ability to recognize revenue for certain contracts where collectability is in question, its accounting for contributions in aid of construction, bundled sales contracts and contracts with pricing provisions that may require it to recognize revenue at prices other than the contract price (e.g., straight line or estimated future market prices). In addition, the Registrants will be required to capitalize costs to acquire new contracts, whereas Exelon currently expenses those costs as incurred. The guidance is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants do not plan to early adopt the standard. In March 2016, the FASB issued a final amendment to clarify the implementation guidance for principal versus agent considerations and in April 2016 issued a final amendment to clarify the guidance related to identifying performance obligations and the accounting for licenses of intellectual property. The Registrants do not expect significant impacts based on these updates. In May 2016, the FASB issued a final amendment regarding narrow scope improvements and practical expedients. The Registrants are currently assessing the impact of this update.

Leases

In February 2016, the FASB issued authoritative guidance to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The guidance requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas today only financing type lease liabilities (capital leases) are recognized in the balance sheet. This is expected to require significant changes to systems, processes and procedures in order to recognize and measure leases recorded on the balance sheet that are currently classified as operating leases. In addition, the definition of a lease has been revised in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement which may result in changes to the classification of an arrangement as a lease. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from current GAAP. The accounting applied by a lessor is largely unchanged from that applied under current GAAP. The standard is effective for fiscal years beginning after December 15, 2018 with early adoption permitted. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the potential to early adopt the guidance.

Intra-Entity Transfers of Assets Other Than Inventory

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

period of adoption. The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the potential to early adopt the guidance.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued authoritative guidance intended to add or clarify guidance on the classification of certain cash receipts and payments on the statement of cash flows. The new guidance addresses cash flows related to the following: debt prepayment or extinguishment costs, settlement of zero-coupon bonds, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies and bank-owned life insurance policies, distributions received from equity method investees, beneficial interest in securitization transactions, and the application of the predominance principle to separately identifiable cash flows. The standard is effective January 1, 2018, with early adoption permitted. The guidance must be applied on a retrospective basis. The Registrants are currently assessing the impacts this guidance may have on their Consolidated Statements of Cash Flows.

Impairment of Financial Instruments

In June 2016, the FASB issued authoritative guidance that adds an impairment model to U.S. GAAP called the Current Expected Credit Loss (CECL) model for financial instruments within the scope of the guidance, which includes loans, trade receivables, debt securities classified as held-to-maturity and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity would be required to recognize an allowance that reflects the entity s current estimate of credit losses expected to be incurred over the life of the financial instrument. An entity must consider all available relevant information when estimating expected credit losses. Historical charge-off rates may be used as a starting point for determining expected credit losses; however, the entity must also evaluate how conditions that existed during the historical charge-off period may differ from its current expectations and accordingly revise its estimate of expected credit losses. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020. The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures.

Improvements to Employee Share-Based Payment Accounting

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

Simplifying the Transition to the Equity Method of Accounting

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships

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

Contingent Put and Call Options in Debt Instruments

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

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued authoritative guidance which (i) requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at amortized cost at the amount that would be received to sell the asset or paid to transfer the liability. The standard is effective for fiscal years beginning after December 15, 2017 with early adoption permitted. The guidance is required to be applied retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures as well as the potential to early adopt the guidance.

Simplifying the Measurement of Inventory

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

3. Variable Interest Entities (All Registrants)

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

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

Consolidated Variable Interest Entities

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor will contribute up to a total of $250 million of equity incrementally from inception through December 2016 in proportion to their ownership interests, which equates up to approximately $172 million for the tax equity investor and up to $78 million for Generation (see Note 18 Commitments and Contingencies for more details). The investment in the distributed energy company was evaluated, and it was determined to be a VIE for which Generation is not the primary beneficiary (see additional details in the Unconsolidated Variable Interest Entities section below). As of December 31, 2015, Generation consolidated 2015 ESA Investco, LLC under the voting interest model. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, 2015 ESA Investco, LLC meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner. (For additional details related to the new consolidation guidance, see Note 2 New Accounting Pronouncements.) Under VIE guidance, Generation is the primary beneficiary; therefore, the entity continues to be consolidated.

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

- a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,
- a group of companies formed by Generation to build, own and operate other generating facilities,
- certain retail power and gas companies for which Generation is the sole supplier of energy,
- CENG,
- 2015 ESA Investco, LLC,
- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property, and
- ATF, a special purpose entity formed by ACE for the purpose of securitizing authorized portions of ACE s recoverable stranded costs through the issuance and sale of transition bonds.

As of September 30, 2016 and December 31, 2015, ComEd, PECO, Pepco and DPL did not have any material consolidated VIEs.

As of September 30, 2016 and December 31, 2015, Exelon, Generation, BGE, PHI and ACE provided the following support to their respective consolidated VIEs:

- Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance of the solar and wind power facilities and there is limited recourse to Generation related to certain solar and wind entities.
- Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 26 Related Party Transactions of the Exelon 2015 Form 10-K for additional information regarding Generation s and Exelon s transactions with CENG):
  - under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF,

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

under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs have been suspended during the term of the Reliability Support Services Agreement (RSSA) (see Note 5 Regulatory Matters for additional details),

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation s obligations under this Indemnity Agreement. (See Note 18 Commitments and Contingencies for more details),

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

Generation and EDF share in the $637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance,

Generation provides a guarantee of approximately $8 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 18 Commitments and Contingencies for more details), and

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

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

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

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

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

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

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

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

65

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Exelon, Generation, BGE, PHI and ACE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and

the creditors of the VIEs did not have recourse to Exelon s, Generation s, BGE s, PHI s or ACE s general credit.

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

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

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

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 September 30, 2016 and December 31, 2015, these assets and liabilities primarily consisted of the following:

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes certain purchase accounting adjustments not pushed down to the ACE standalone entity.
(c) Includes the CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid pension asset line item on Generation s balance sheet. See Note 13 Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is reflected on Exelon s and Generation s Consolidated Balance Sheets in Investments. For the energy purchase and sale contracts (commercial agreements), the carrying amount of assets and liabilities in Exelon s and Generation s Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon and Generation for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon and Generation have not provided material debt or equity support, liquidity arrangements or performance guarantees associated with these commercial agreements.

The Registrants unconsolidated VIEs consist of:

Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.

Asset sale agreement with ZionSolutions, LLC and EnergySolutions, Inc. in which Generation has a variable interest but has concluded that consolidation is not required.

Equity investments in energy development companies, distributed energy companies, and energy generating facilities for which Generation has concluded that consolidation is not required.

As of September 30, 2016 and December 31, 2015, Exelon and Generation had significant unconsolidated variable interests in nine and eight VIEs, respectively for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $20 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $20 million included in Investments on Exelon s and Generation s Consolidated Balance Sheets. The risk of a loss was assessed to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss.

In July 2014, Generation entered into an arrangement to purchase a 90% equity interest and 90% of the tax attributes of a distributed energy company. Generation s total equity commitment in this arrangement was $91 million and was paid incrementally over an approximate two year period (see Note 18 Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and was recorded as an equity method investment. However, pursuant to the new consolidation guidance effective as of January 1, 2016 for the Registrants, the distributed energy company meets the definition of a VIE because the company has a similar structure to a limited partnership and the limited partners do not have kick out rights of the general partner. (For additional details related to the new consolidation guidance, see Note 2 New Accounting Pronouncements.) Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method.

In June 2015, 2015 ESA Investco, LLC, then a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of a distributed energy company,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

which is an unconsolidated VIE. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible promissory note. In November 2015, Generation sold 69% of its equity interest in 2015 ESA Investco, LLC to a tax equity investor. Generation and the tax equity investor will contribute up to a total of $250 million of equity incrementally from inception through December 2016 in proportion of their ownership interests, which equates up to approximately $172 million for the tax equity investor and up to $78 million for Generation (see Note 18 Commitments and Contingencies for additional details). Generation and the tax equity investor provide a parental guarantee of up to $275 million in proportion to their ownership interests in support of 2015 ESA Investco, LLC s obligation to make equity contributions to the distributed energy company, which is an unconsolidated VIE. The investment in the distributed energy company was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. See additional details in the Consolidated Variable Interest Entities section above.

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

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

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

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

(b) These items represent amounts on Exelon s and Generation s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $135 million and $206 million as of September 30, 2016 and December 31, 2015, respectively; offset by payables to ZionSolutions LLC of $124 million and $189 million as of September 30, 2016 and December 31, 2015, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

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

Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a most favored nation provision which, generally speaking, requires allocation of merger benefits proportionally across all the jurisdictions. In the first quarter of 2016, Exelon estimated and recorded total nominal cost commitments of $508 million, excluding renewable generation commitments (approximately $444 million on a net present value basis, excluding renewable generation commitments and charitable contributions).

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following amounts were recognized as total commitment costs in Operating and maintenance expense in Exelon s, PHI s, Pepco s, DPL s and ACE s Consolidated Statements of Operations and Comprehensive Income for the nine months ended September 30, 2016 and PHI s successor period:

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

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

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

In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new generation in Maryland, District of Columbia, and Delaware, 27 MWs of which are expected to be completed by 2018. These investments are expected to total approximately $137 million, are expected to be primarily capital in nature, and will generate future earnings at Exelon and Generation. The actual cost of investment in new generation may differ depending on the result of final negotiations and application of the most favored nation provision. Investment costs will be recognized as incurred and recorded on Exelon s and Generation s financial statements. Exelon has also committed to purchase 100 MWs of wind energy in PJM, to procure 120 MWs of wind RECs for the purpose of meeting Delaware s renewable portfolio standards, and to maintain and promote energy efficiency and demand response programs in the PHI jurisdictions.

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

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

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger and in July and August, Exelon, PHI, the MDPSC, Prince George s County and Montgomery County filed responses opposing the motions to stay. The judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the

Circuit Court

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

judge affirmed the MDPSC s order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed a notice of appeal. Exelon believes the matters are without merit. These appeals are not expected to be resolved any earlier than the first quarter of 2017.

Between March 25, 2016 and April 22, 2016, various parties filed motions with the DCPSC to reconsider its March 23, 2016 order approving the merger. On June 17, 2016, the DCPSC denied all motions. In August 2016, the District of Columbia Office of People s Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC s March 23, 2016 order with the District of Columbia Court of Appeals. On September 9, 2016, the Court consolidated the appeals. Although the Court has not yet issued a scheduling order, a decision on this matter is not expected until the second or third quarter of 2017. Exelon believes the matters are without merit.

Accounting for the Merger Transaction

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

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

(a) As of December 31, 2015, the preferred stock was included in Other non-current assets on Exelon s Consolidated Balance Sheets.
(b) PHI s unvested time-based restricted stock units and performance-based restricted stock units issued prior to April 29, 2014 were immediately vested and paid in cash upon the close of the merger. PHI s remaining unvested time-based restricted stock units as of the close of the merger were cancelled. There were no remaining unvested performance-based restricted stock units as of the close of the merger.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

The fair values of PHI s assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows, future market prices and impacts of utility rate regulation. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired.

73

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 nine months ended September 30, 2016 was as follows:

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

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

Through its wholly-owned rate regulated utility subsidiaries, most of PHI s assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate base, generally measured at historical cost. In applying the acquisition method of accounting, for regulated assets and liabilities included in rate base or otherwise earning a return (primarily property, plant and equipment and regulatory assets earning a return), no fair value adjustments were recorded as historical cost is viewed as a reasonable proxy for fair value.

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

Fair value adjustments were recorded at Exelon and PHI for the difference between the contract price and the market price of electricity and gas energy supply contracts of PHI s wholly-owned rate regulated utility subsidiaries. These adjustments are intangible assets and liabilities classified as unamortized energy contracts on Exelon s and PHI s Consolidated Balance Sheets as of September 30, 2016. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchase power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

The current impact of PHI, including its unregulated businesses, on Exelon s Consolidated Statements of Operations and Comprehensive Income includes Operating revenues of $1.4 billion and Net income of $169 million during the three months ended September 30, 2016, and Operating revenues of $2.7 billion and Net loss of $(92) million during the nine months ended September 30, 2016.

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

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

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

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

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

(c) For the nine months ended September 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $10 million, $3 million and $13 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters for more information.

Pro-forma Impact of the Merger

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,		Year Ended December 31,
	2016[a]	2015[b]	2016[a]	2015[b]	2015[c]
Total operating revenues	$ 9,002	$ 8,545	$ 24,468	$ 26,129	$ 33,823
Net income attributable to common shareholders	501	746	1,346	2,169	2,618
Basic earnings per share	$ 0.54	$ 0.81	$ 1.46	$ 2.36	$ 2.85
Diluted earnings per share	0.54	0.81	1.45	2.35	2.84

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

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

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

Acquisition of ConEdison Solutions (Exelon and Generation)

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

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

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

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

76

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

The fair values of ConEdison Solutions assets and liabilities were determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing), discount rates reflecting risk inherent in the future cash flows and future power and fuel market prices.

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

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Asset Divestitures (Exelon, Generation, PHI and Pepco)

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

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

On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. See Note 10 Debt and Credit Agreements for more information. As of September 30, 2016, $46 million of Property, plant and equipment and $5 million of Asset retirement obligation are classified as held for sale within Other current assets and Other current liabilities, respectively, on Exelon s and Generation s Consolidated Balance Sheets. In October 2016, Generation entered into an agreement to sell a portion of the Upstream assets which is expected to close before December 31, 2016.

In July 2016, DPL completed the sale of a 9 acre land parcel located on South Madison Street in Wilmington, DE, resulting in a pre-tax gain of approximately $4 million. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in the Exelon and PHI Consolidated Statements of Operations and Comprehensive Income.

5. Regulatory Matters (All Registrants)

Except for the matters noted below, the disclosures set forth in Note 3 Regulatory Matters of the Exelon 2015 Form 10-K and Note 7 Regulatory Matters of the PHI 2015 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

Illinois Regulatory Matters

Distribution Formula Rate (Exelon and ComEd). On April 13, 2016, ComEd filed its annual distribution formula rate with the ICC pursuant to EIMA. The filing establishes the revenue requirement used to set the rates that will take effect in January 2017 after the ICC s review and approval, which is due by December 2016. The revenue requirement requested is based on 2015 actual costs plus projected 2016 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2015 to the actual costs incurred that year. ComEd s 2016 filing request includes a total increase to the revenue requirement of $138 million, reflecting an increase of $139 million for the initial revenue requirement for 2017 and a decrease of $1 million related to the annual reconciliation for 2015. The revenue requirement for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.71% inclusive of an allowed ROE of 8.64%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2015 provided for a weighted average debt and equity return on distribution rate base of 6.69% inclusive of an allowed ROE of 8.59%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points. See table below for ComEd s regulatory assets associated with its distribution formula rate. For additional information on ComEd s distribution formula rate filings see Note 3 Regulatory Matters of the Exelon 2015 Form 10-K.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Pennsylvania Regulatory Matters

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

On March 17, 2016, PECO filed its fourth DSP Program with the PAPUC proposing a 24-month term from June 1, 2017 through May 31, 2019, in compliance with electric generation procurement guidelines set forth in Act 129. On October 4, 2016, the Administrative Law Judge recommended that PECO s previously filed partial settlement be approved without modification. The settlement would extend the program period through May 2021 and consolidate the Medium Commercial and Large Commercial classes of default service customers into a Consolidated Large Commercial Class proposed by the Company. The issue of PECO s implementation of CAP Shopping was reserved for briefing, and the Administrative Law Judge determined that issue was not a part of the DSP IV case. A decision by the PAPUC is expected in December 2016.

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Maryland Regulatory Matters

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of September 30, 2016 and December 31, 2015, the balance of BGE s regulatory asset was $235 million and $196 million, respectively, representing incremental program deployment costs. The current quarter balance of $235 million consists of three major components, including $148 million of unamortized incremental deployment costs of the AMI program, $55 million of unamortized costs of the non-AMI meters replaced under the program, and $32 million related to post-test year incremental program deployment costs incurred prior to approval became effective June 2016. The balance as of September 30, 2016 reflects the impact of the cost disallowances and adjustments discussed below. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being recovered through rates and amortized to expense over a 10 year period, while the post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC. A return on the regulatory asset is currently included in rates, except for the $55 million portion representing the unamortized cost of the retired non-AMI meters and a $32 million portion related to post-test year incremental program deployment costs.

As part of the 2015 electric and natural gas distribution rate case filed on November 6, 2015, BGE sought recovery of its smart grid initiative costs, supported by evidence demonstrating that BGE had, in fact, implemented a cost-beneficial advanced metering system. On June 3, 2016, the MDPSC issued an order concluding that the smart grid initiative overall is cost beneficial to its customers. However, the June 3 order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for non-AMI meters replaced under the program. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting that the MDPSC modify its order to reverse certain decisions and change certain of the cost disallowances and adjustments to enable BGE to defer those costs for recovery through future electric and natural gas rates. OPC also subsequently filed for a petition for rehearing of the June 3 order. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that reversed certain of its prior cost disallowances and adjustments related to the smart grid initiative. On August 26, 2016, BGE filed an appeal of the MDPSC s orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC s order but with the Circuit Court for Baltimore City. BGE cannot predict the outcomes of these appeals.

As a combined result of the MDPSC orders, BGE recorded a $52 million charge to Operating and maintenance expense in Exelon s and BGE s Consolidated Statements of Operations and Comprehensive Income

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Delaware Regulatory Matters

2016 Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allowed DPL to put into effect $2.5 million of the rate increase two months after filing the applications which were effective July 16, 2016. It also allows the entire requested rate increase seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. DPL cannot predict how much of the requested increase the DPSC will approve.

District of Columbia Regulatory Matters

2016 Electric Distribution Base Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, which was updated to $82 million on October 14, 2016, based on a requested ROE of 10.6%. The DCPSC has issued a procedural schedule indicating a final decision will be issued by July 25, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect soon thereafter. Pepco cannot predict how much of the requested increase the DCPSC will approve.

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

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

The Improvement Financing Act provides that: (i) Pepco is to fund approximately $500 million of the estimated cost to complete the DC PLUG initiative, recovering those costs through a volumetric surcharge on the electric bills of Pepco District of Columbia customers; (ii) $375 million of the DC PLUG initiative cost is to be financed by the District of Columbia s issuance of securitized bonds, which bonds will be repaid through a volumetric surcharge (the DDOT surcharge) on the electric bills of Pepco District of Columbia customers that Pepco will remit to the District of Columbia; and (iii) the remaining costs up to $125 million are to be covered by the existing capital projects program of the District of Columbia Department of Transportation (DDOT). Pepco will not earn a return on or a return of the cost of the assets funded with the proceeds of the securitized bonds or assets that are constructed by DDOT under its capital projects program, but ownership and responsibility for the operation and maintenance of such assets will be transferred to Pepco for a nominal amount.

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

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

New Jersey Regulatory Matters

2016 Electric Distribution Base Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, and an increase of $45 million (before New Jersey sales and use tax) to its electric distribution base rates, with the new rates effective immediately. The stipulation of settlement provided that a determination on PowerAhead would be separated into a phase II of the rate proceeding and decided at a later date and the parties would seek to resolve the matter by the end of 2016, although resolution will most likely occur in the first quarter of 2017. PowerAhead includes capital investments to advance modernization of the electric grid through energy efficiency, increased distributed generation, and resiliency, focused on improving the distribution system s ability to withstand major storm events. ACE cannot predict if the NJBPU will approve the PowerAhead initiative.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). *O*n February 1, 2016, ACE submitted its 2016 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE s long-term power purchase contracts with the NUGs and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE s uncollectible accounts.

The net impact of adjusting the charges as proposed is an overall annual rate increase of $9 million (revised to $19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax. The matter is pending at the NJBPU.

New York Regulatory Matters

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the Clean Energy Standard (CES), a component of which includes creation of a Tier 3 Zero Emission Credit (ZEC) program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined by the federal government. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills. The CES initially identifies the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. The program specifically provides that Nine Mile Point Units 1 & 2 qualify jointly as a single facility and if either unit permanently ceases operations then both units will no longer qualify for ZEC payments for the remainder of the program. As issued, the order provides that the duration of the program beyond the first tranche is conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018; however, Generation and CENG requested clarification, or in the alternative limited rehearing, that this condition is applicable to the FitzPatrick facility only and has no bearing on the 12-year duration of the program for Ginna or Nine Mile Point. To date, several parties have filed with the NYPSC requests for rehearing or reconsideration of the CES and on October 19, 2016, a coalition of fossil generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically that the ZEC program interferes with FERC s jurisdiction over wholesale rates and that it discriminates against out of state competitors. Generation and CENG will seek to intervene in the case and to dismiss the lawsuit. Other legal challenges remain possible and the outcomes of each of these challenges are currently uncertain. Negotiations with NYSERDA regarding contracts for the sale of ZECs from Ginna, Nine Mile Point and FitzPatrick are ongoing, and Generation expects that NYSERDA will enter into final agreements during the fourth quarter of 2016. See Note 7 Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point. See Note 4 Mergers, Acquisitions and Dispositions for additional information on Generation s proposed acquisition of FitzPatrick.

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

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

later than September 30, 2016. Under the terms of the RSSA, if Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments up to a maximum of $20 million to RG&E related to capital expenditures. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the CES. As a result, Ginna has reserved the right to withdraw this notification and cease commercial operations if the ZEC program is terminated, suspended, or stayed prior to commencement of the program on April 1, 2017 or if for any reason a contract with NYSERDA in a form and substance satisfactory to Generation and CENG is not executed for Ginna, Nine Mile Point, or FitzPatrick. Negotiations with NYSERDA are ongoing and contract execution is currently targeted for completion in the fourth quarter of 2016.

There remains an increased risk that, for economic reasons, Ginna could be retired before the end of its operating license period in 2029. In the event the plant were to be retired before the current license term ends in 2029, Exelon s and Generation s results of operations could be adversely affected by the accelerated future decommissioning costs, severance costs, increased depreciation rates, and impairment charges, among other items. See Note 7-Early Nuclear Plant Retirements for further information regarding the impacts of a decision to early retire one or more nuclear plants.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). ComEd s, BGE s, Pepco s, DPL s and ACE s transmission rates are each established based on a FERC-approved formula. ComEd, BGE, Pepco, DPL, and ACE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd, BGE, Pepco, DPL, and ACE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd s, BGE s, Pepco s, DPL s and ACE s best estimate of the revenue requirement expected to be filed with the FERC for that year s reconciliation. The regulatory asset associated with transmission true-up is amortized to Operating revenues within their Consolidated Statements of Operations of Comprehensive Income as the associated amounts are recovered through rates.

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

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

(a) All rates are effective June 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

In August 2009, the court issued its decision affirming the FERC s order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants filed an Offer of Settlement with FERC. Each state that is a party in this proceeding either signed, or will not oppose, the settlement. On July 5, 2016, a number of merchant transmission owners and load servicing entities opposed the Settlement in whole or in part. As of September 30, 2016, the Settlement is awaiting FERC s action. If the Settlement is approved, effective January 1, 2016, for the costs of the 500 kV facilities approved by the PJM Board on or after February 1, 2013, 50% will be socialized across PJM and 50% will be allocated according to an engineering formula that calculates the flows on the transmission facilities. The Settlement includes provisions for monthly credits or charges that are expected to be mostly refunded or recovered through customer rates over a 10-year period based on negotiated numbers for charges prior to January 1, 2016.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

On August 29, 2012, Generation submitted a hydroelectric license application to FERC for a 46-year license for the Conowingo Hydroelectric Project (Conowingo). In connection with Generation s efforts to obtain a water quality certification pursuant to Section 401 of the Clean Water Act with Maryland Department of the Environment (MDE) for Conowingo, Generation continues to work with MDE and other stakeholders to resolve water quality licensing issues, including: (1) water quality, (2) fish habitat, and (3) sediment. In addition, Generation continues to work with MDE and other Federal and Maryland state agencies to conduct and fund an additional sediment and nutrient monitoring study.

On August 7, 2015, US Fish and Wildlife Service of the US Department of the Interior (Interior) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge Interior s preliminary prescription. On April 21, 2016, Exelon and Interior executed a Settlement Agreement resolving all fish passage issues between the parties. Accordingly, on April 22, 2016, Exelon withdrew its Request for a Trial-Type Hearing and Alternative Prescription. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 46-year life of the new license, including both capital and operating costs. The actual timing and amount of these costs are not currently fixed and may vary significantly from year to year throughout the life of the new license. Resolution of the remaining issues relating to Conowingo involving various stakeholders may have a material effect on Exelon s and Generation s results of operations and financial position through an increase in capital expenditures and operating costs. As of September 30, 2016, $27 million of direct costs associated with the Conowingo licensing effort have been capitalized. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information on Generation s operating license renewal efforts.

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

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

As a result of applying the acquisition method of accounting and pushing it down to the consolidated financial statements of PHI, certain regulatory assets and liabilities were established at Exelon and PHI to offset the impacts of fair valuing the acquired assets and liabilities assumed which are subject to regulatory recovery. In total, Exelon and PHI recorded a net $2.4 billion regulatory asset reflecting adjustments recorded as a result of the acquisition method of accounting. See Note 4 Mergers, Acquisitions and Dispositions for additional information.

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

(a) As of September 30, 2016, the pension and other postretirement benefits regulatory asset at Exelon includes regulatory assets of $1,087 million established at the date of the PHI Merger related to unrecognized costs that are probable of regulatory recovery. The regulatory assets are amortized over periods from 3 to 15 years, depending on the underlying component. Pepco, DPL and ACE are currently recovering these costs through base rates. Pepco, DPL and ACE are not earning a return on the recovery of these costs in base rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

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

Long-Lived Assets (Exelon and Generation)

During the first quarter of 2016, significant changes in Generation s intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its upstream subsidiary CEU Holdings, LLC (as described in Note 10 Debt and Credit Agreements) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt, see Note 10 Debt and Credit Agreements for additional information. As a result, the Upstream assets and liabilities are classified as held for sale on Exelon s and Generation s Consolidated Balance Sheets at September 30, 2016. See Note 4 Mergers, Acquisitions and Dispositions for additional information. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value.

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

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 2016, updates to the Company s long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than their carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result of the fair value analysis, long-lived merchant wind assets held and used with a carrying amount of approximately $60 million were written down to their fair value of $24 million and a pre-tax impairment charge of $36 million was recorded during the second quarter in Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

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

Like-Kind Exchange Transaction (Exelon)

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

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

7. Early Nuclear Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation s nuclear plants. Factors that will continue to affect the economic value of Generation s nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

In 2016, as a result of the plant retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $146 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of Clinton and Quad Cities primarily related to accelerated depreciation of plant assets (including any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions. Through September 30, 2016, Exelon s and Generation s results include an incremental $443 million of pre-tax expense for these items as summarized in the table below. Please refer to Note 12 Nuclear Decommissioning for additional detail on changes to the Nuclear decommissioning ARO balances resulting from the early retirement of Clinton and Quad Cities.

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

(a) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(b) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Assuming the successful implementation of the CES and its continued effectiveness, Generation and CENG would no longer consider Ginna and Nine Mile Point to be at heightened risk of early retirement; however, absent the CES for the full expected duration they will remain at heightened risk. The precise timing of an early retirement date for any of these plants, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) and preferred stock as of September 30, 2016 and December 31, 2015:

Exelon

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

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

Generation

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

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

ComEd

September 30, 2016

Fair Value

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

PECO

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

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

BGE

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

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

PHI

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

December 31, 2015

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Pepco

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

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

DPL

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

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

ACE

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

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

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

(b) Includes unamortized debt issuance costs which are not fair valued of $7 million, $1 million, and $6 million for Exelon, ComEd and BGE, respectively, as of September 30, 2016 and December 31, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

SNF Obligation. The carrying amount of Generation s SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation s nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation s discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Recurring Fair Value Measurements

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

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

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

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

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Additionally, there were no significant transfers between Level 1 and Level 2 during the nine months ended September 30, 2016 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations. For derivative contracts, transfers into Level 2 from Level 3 generally occur when the contract tenor becomes more observable and due to changes in market liquidity or assumptions for certain commodity contracts.

Generation and Exelon

In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under Not subject to leveling in the table below. See Note 2 New Accounting Pronouncements for additional information.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

	Generation					Exelon				
As of September 30, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[(a)]	$ 94	$	$	$	$ 94	$ 1,645	$	$	$	$ 1,645
NDT fund investments										
Cash equivalents[(b)]	163	20			183	163	20			183
Equities	3,566	335		1,992	5,893	3,566	335		1,992	5,893
Fixed income										
Corporate debt		1,629	257		1,886		1,629	257		1,886
U.S. Treasury and agencies	1,363	33			1,396	1,363	33			1,396
Foreign governments		50			50		50			50
State and municipal debt		268			268		268			268
Other[(c)]		56		510	566		56		510	566
Fixed income subtotal	1,363	2,036	257	510	4,166	1,363	2,036	257	510	4,166
Middle market lending			436	23	459			436	23	459
Private equity				138	138				138	138
Real estate				306	306				306	306
NDT fund investments subtotal[(d)]	5,092	2,391	693	2,969	11,145	5,092	2,391	693	2,969	11,145
Pledged assets for Zion Station decommissioning										
Cash equivalents	14				14	14				14
Equities		1			1		1			1
Fixed income										
U.S. Treasury and agencies	28	2			30	28	2			30
Corporate debt		3			3		3			3
Fixed income subtotal	28	5			33	28	5			33
Middle market lending			19	68	87			19	68	87
Pledged assets for Zion Station decommissioning subtotal[(e)]	42	6	19	68	135	42	6	19	68	135
Rabbi trust investments										
Cash equivalents	10				10	83				83
Mutual funds	19				19	50				50
Fixed income							14			14
Life insurance contracts		18			18		64	21		85
Rabbi trust investments subtotal	29	18			47	133	78	21		232

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					Exelon				
As of September 30, 2016	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Liabilities										
Commodity derivative liabilities										
Economic hedges	(1,037)	(2,917)	(1,160)		(5,114)	(1,037)	(2,917)	(1,404)		(5,358)
Proprietary trading	(10)	(53)	(39)		(102)	(10)	(53)	(39)		(102)
Effect of netting and allocation of collateral[f]	1,012	2,777	1,046		4,835	1,012	2,777	1,046		4,835
Commodity derivative liabilities subtotal	(35)	(193)	(153)		(381)	(35)	(193)	(397)		(625)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(18)			(18)		(18)			(18)
Economic hedges		(19)			(19)		(19)			(19)
Proprietary trading	(6)				(6)	(6)				(6)
Effect of netting and allocation of collateral	8	16			24	8	16			24
Interest rate and foreign currency derivative liabilities subtotal	2	(21)			(19)	2	(21)			(19)
Deferred compensation obligation		(32)			(32)		(131)			(131)
Total liabilities	(33)	(246)	(153)		(432)	(33)	(345)	(397)		(775)
Total net assets	$ 5,194	$ 2,495	$ 1,689	$ 3,037	$ 12,415	$ 6,849	$ 2,495	$ 1,466	$ 3,037	$ 13,847

	Generation					Exelon				
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Assets										
Cash equivalents[a]	$ 104	$	$	$	$ 104	$ 5,766	$	$	$	$ 5,766
NDT fund investments										
Cash equivalents[b]	219	92			311	219	92			311
Equities	3,008			1,894	4,902	3,008			1,894	4,902
Fixed income										
Corporate debt		1,824	242		2,066		1,824	242		2,066
U.S. Treasury and agencies	1,323	15			1,338	1,323	15			1,338
Foreign governments		61			61		61			61
State and municipal debt		326			326		326			326
Other[c]		147		390	537		147		390	537
Fixed income subtotal	1,323	2,373	242	390	4,328	1,323	2,373	242	390	4,328
Middle market lending			428		428			428		428
Private equity				125	125				125	125
Real estate				35	35				35	35
Other				216	216				216	216

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

104

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					Exelon				
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Not subject to leveling**	**Total**
Rabbi trust investments										
Mutual funds	17				17	48				48
Life insurance contracts		13			13		36			36
Rabbi trust investments subtotal	17	13			30	48	36			84
Commodity derivative assets										
Economic hedges	1,922	3,467	1,707		7,096	1,922	3,467	1,707		7,096
Proprietary trading	36	64	30		130	36	64	30		130
Effect of netting and allocation of collateral[(f)]	(1,964)	(2,629)	(564)		(5,157)	(1,964)	(2,629)	(564)		(5,157)
Commodity derivative assets subtotal	(6)	902	1,173		2,069	(6)	902	1,173		2,069
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments							25			25
Economic hedges		20			20		20			20
Proprietary trading	10	5			15	10	5			15
Effect of netting and allocation of collateral	(3)	(3)			(6)	(3)	(3)			(6)
Interest rate and foreign currency derivative assets subtotal	7	22			29	7	47			54
Other investments			33		33			33		33
Total assets	4,679	3,473	1,898	2,765	12,815	10,372	3,521	1,898	2,765	18,556
Liabilities										
Commodity derivative liabilities										
Economic hedges	(2,382)	(3,348)	(850)		(6,580)	(2,382)	(3,348)	(1,097)		(6,827)
Proprietary trading	(33)	(57)	(37)		(127)	(33)	(57)	(37)		(127)
Effect of netting and allocation of collateral[(f)]	2,440	3,186	765		6,391	2,440	3,186	765		6,391
Commodity derivative liabilities subtotal	25	(219)	(122)		(316)	25	(219)	(369)		(563)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments		(16)			(16)		(16)			(16)
Economic hedges		(3)			(3)		(3)			(3)
Proprietary trading	(12)				(12)	(12)				(12)
Effect of netting and allocation of collateral	12	3			15	12	3			15
Interest rate and foreign currency derivative liabilities subtotal		(16)			(16)		(16)			(16)
Deferred compensation obligation		(30)			(30)		(99)			(99)
Total liabilities	25	(265)	(122)		(362)	25	(334)	(369)		(678)

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

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

ComEd, PECO and BGE

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

	ComEd				PECO				BGE			
As of September 30, 2016	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$	$	$	$	$ 521	$	$	$ 521	$ 375	$	$	$ 375
Rabbi trust investments												
Mutual funds					7			7	4			4
Life insurance contracts						11		11				
Rabbi trust investments subtotal					7	11		18	4			4
Total assets					528	11		539	379			379
Liabilities												
Deferred compensation obligation		(8)		(8)		(10)		(10)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(244)	(244)								
Total liabilities		(8)	(244)	(252)		(10)		(10)		(4)		(4)
Total net assets (liabilities)	$	$ (8)	$ (244)	$ (252)	$ 528	$ 1	$	$ 529	$ 379	$ (4)	$	$ 375

106

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	ComEd				PECO				BGE			
As of December 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets												
Cash equivalents[(a)]	$ 29	$	$	$ 29	$ 271	$	$	$ 271	$ 25	$	$	$ 25
Rabbi trust investments												
Mutual funds					8			8	4			4
Life insurance contracts						12		12				
Rabbi trust investments subtotal					8	12		20	4			4
Total assets	29			29	279	12		291	29			29
Liabilities												
Deferred compensation obligation		(8)		(8)		(12)		(12)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(247)	(247)								
Total liabilities		(8)	(247)	(255)		(12)		(12)		(4)		(4)
Total net assets (liabilities)	$ 29	$ (8)	$ (247)	$ (226)	$ 279	$	$	$ 279	$ 29	$ (4)	$	$ 25

(a) ComEd excludes cash of $44 million and $38 million at September 30, 2016 and December 31, 2015 and restricted cash of $2 million and $2 million at September 30, 2016 and December 31, 2015. PECO excludes cash of $27 million and $27 million at September 30, 2016 and December 31, 2015 and $1 million of restricted cash at September 30, 2016. BGE excludes cash of $13 million and $6 million at September 30, 2016 and December 31, 2015 and restricted cash of $2 million and $2 million at September 30, 2016 and December 31, 2015 and includes long term restricted cash of $3 million at September 30, 2016, which is reported in other deferred debits on the balance sheet.

(b) The Level 3 balance consists of the current and noncurrent liability of $19 million and $225 million, respectively, at September 30, 2016, and $23 million and $224 million, respectively, at December 31, 2015, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PHI, Pepco, DPL and ACE

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					ComEd	*Successor* PHI[c]		Exelon
Nine Months Ended September 30, 2016	**NDT Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[a]**	**Life Insurance Contracts**	**Eliminated in Consolidation**	**Total**
Balance as of December 31, 2015	$ 670	$ 22	$ 1,051	$ 33	$ 1,776	$ (247)	$	$	$ 1,529
Included due to merger							20		20
Total realized / unrealized gains (losses)									
Included in net income	2		(339)[b]	1	(336)		2		(334)
Included in noncurrent payables to affiliates	18				18			(18)	
Included in payable for Zion Station decommissioning		1			1				1
Included in regulatory assets/liabilities						3		18	21
Change in collateral			(51)		(51)				(51)
Purchases, sales, issuances and settlements									
Purchases	123	1	289[d]	7	420				420
Sales	(1)	(5)	(5)		(11)				(11)
Issuances							(1)		(1)
Settlements	(119)				(119)				(119)
Transfers into Level 3			1	1	2				2
Transfers out of Level 3			(11)		(11)				(11)
Balance as of September 30, 2016	$ 693	$ 19	$ 935	$ 42	$ 1,689	$ (244)	$ 21	$	$ 1,466
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of September 30, 2016	$ 7	$	$ 240	$	$ 247	$	$ 1	$	$ 248

(a) Includes $25 million of decreases in fair value and realized losses due to settlements of $2 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2016. Includes $10 million of decreases in fair value and realized losses due to settlements of $13 million for the nine months ended September 30, 2016.
(b) Includes a reduction for the reclassification of $190 million and $579 million of realized gains due to the settlement of derivative contracts recorded in results of operations for the three and nine months ended September 30, 2016, respectively.
(c) Successor period represents activity from March 24, 2016 through September 30, 2016. See tables below for PHI s predecessor periods, as well as activity for Pepco and DPL for the three and nine months ended September 30, 2016.
(d) Includes $168 million of fair value from contracts acquired as a result of portfolio acquisitions.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

112

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(a) Includes $19 million of decreases in fair value and a reduction for realized gains due to settlements of $1 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2015. Includes $44 million of decreases in fair value and an increase for realized losses due to settlements of $8 million for the nine months ended September 30, 2015.

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

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

Ending Balance	$ 21	$ 18	$ 19
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$	$ 15	$

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

	Three Months Ended September 30, 2016 Pepco Life Insurance Contracts	Three Months Ended September 30, 2015 Pepco Life Insurance Contracts
Beginning Balance	$ 20	$ 20
Total realized / unrealized gains (losses)		
Included in net income	1	1
Purchases, sales, issuances and settlements		
Issuances		(3)
Settlements		
Ending Balance	$ 21	$ 18
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$	$

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

Settlements						(1)
Ending Balance	$	21	$	18	$	
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities for the period	$	2	$	2	$	

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Valuation Techniques Used to Determine Fair Value

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

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

Preferred Stock Derivative (PHI). In connection with entering into the PHI Merger Agreement, as further described in Note 16 Mezzanine Equity, PHI entered into a Subscription Agreement with Exelon dated April 29, 2014, pursuant to which PHI issued to Exelon shares of Preferred stock. The Preferred stock contained embedded features requiring separate accounting consideration to reflect the potential value to PHI that any issued and outstanding Preferred stock could be called and redeemed at a nominal par value upon a termination of the merger agreement under certain circumstances due to the failure to obtain required regulatory approvals. The embedded call and redemption features on the shares of the Preferred stock in the event of such a termination were separately accounted for as derivatives. These Preferred stock derivatives were valued quarterly using quantitative and qualitative factors, including management s assessment of the likelihood of a Regulatory Termination and therefore, were categorized in Level 3 in the fair value hierarchy. As a result of the PHI Merger, the PHI Preferred stock derivative was reduced to zero as of March 23, 2016. The write-off was charged to Other, net on the PHI Consolidated Statement of Operations and Comprehensive Income.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Middle market lending are investments in loans or managed funds which lend to private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models and income models. Investments in loans are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Managed funds are valued using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity and real estate investments include those in limited partnerships that invest in operating companies and real estate holding companies that are not publicly traded on a stock exchange, such as, leveraged

Table of Contents

buyouts, growth capital, venture capital, distressed investments, investments in natural resources, and direct investments in pools of real estate properties. The fair value of private equity and real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, are not classified within the fair value hierarchy. These investments typically cannot be redeemed and are generally liquidated over a period of 8 to 10 years from the initial investment date. Private equity and real estate valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows, market based comparable data, and independent appraisals from sources with professional qualifications. These valuation inputs are not highly observable.

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

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of September 30, 2016. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of September 30, 2016, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation s NDT assets.

See Note 12 Nuclear Decommissioning for further discussion on the NDT fund investments.

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

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

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market s expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 9 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

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

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

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

Mark-to-Market Derivatives (Exelon, Generation and ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 9 Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Type of trade	Fair Value at September 30, 2016	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives Economic Hedges (Exelon and Generation)(a)(c)	$ 788	Discounted Cash Flow	Forward power price	$6	$130
			Forward gas price	$1.24	$9.53
		Option Model	Volatility percentage	5%	115%
Mark-to-market derivatives Proprietary trading (Exelon and Generation)(a)(c)	$ (3)	Discounted Cash Flow	Forward power price	$15	$68
Mark-to-market derivatives (Exelon and ComEd)	$ (244)	Discounted Cash Flow	Forward heat rate(b)	8x	9x
			Marketability reserve	3%	8%
			Renewable factor	86%	121%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
(c) The fair values do not include cash collateral posted on level three positions of $150 million as of September 30, 2016.

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

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

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
(c) The fair values do not include cash collateral posted on level three positions of $201 million as of December 31, 2015.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation s commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.

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

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

9. Derivative Financial Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations.

Commodity Price Risk (All Registrants)

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge. For Generation, all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and natural gas supply agreements. Generation has also entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators, as well as contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. These non-derivative contracts are accounted for primarily under the accrual method of accounting. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s overall energy marketing activities.

Economic Hedging. The Registrants are exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies and other factors. Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management s policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of September 30, 2016, the proportion of expected generation hedged for the major reportable segments is 98%-101%, 85%-88% and 54%-57% for 2016, 2017 and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales to the Utility Registrants to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 3 Regulatory Matters of the Exelon 2015 Form 10-K for additional information.

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

PECO s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2016 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2016 PGC settlement, PECO is required to lock in (i.e. economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO s gas-hedging program is designed to cover about 25% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO s financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

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

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

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

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

DPL provides natural gas to its customers under an Annual GCR mechanism approved by the DPSC. Under this mechanism, DPL s Annual GCR Filing establishes a future GCR for firm bundled sales customers by using a forecast of demand and commodity costs. The actual costs are trued up versus the forecast on a monthly basis and any shortfall or excess is carried forward as a recovery balance in the next GCR filing. The demand portion of the GCR is based upon DPL s firm transportation and storage contracts. DPL has firm deliverability of swing and seasonal storage; a liquefied natural gas facility and firm transportation capacity to meet customer demand and provide a reserve margin. The commodity portion of the GCR includes a commission approved hedging program which is intended to reduce gas commodity price volatility while limiting the firm natural gas customers exposure to adverse changes in the market price of natural gas. The hedge program requires that DPL hedge, on a non-discretionary basis, an amount equal to fifty percent (50%) of estimated purchase requirements for each month, including estimated monthly purchases for storage injections. The fifty percent (50%) hedge monthly target is achieved by hedging 1/12th of the 50% target each month beginning 12-months prior to the month in which the physical gas is to be purchased. Currently, DPL uses only exchange traded futures for its Gas Hedging Program, which are considered derivatives, however, it retains the capability to employ other physical and financial hedges if needed. DPL has not elected hedge accounting for these derivative financial instruments. Because of the DPSC-approved fuel adjustment clause for DPL s derivatives, the change in fair value of the derivatives each period, in addition to all premiums paid and other transaction costs incurred as part of the Gas Hedging Program, are fully recoverable and are recorded by DPL as regulatory assets or liabilities. DPL s physical gas purchases are currently all daily, monthly or intra-month transactions. From time to time, DPL will enter into seasonal purchase or sale arrangements, however, there are none currently in the portfolio. Certain of DPL s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. The BGS rates charged recover ACE s wholesale power supply costs. ACE

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

does not make any profit or incur any loss on the supply component of the BGS it supplies to customers. ACE s price risk related to electric supply procurement is limited. ACE locks in fixed prices for all of its BGS requirements through full requirements contracts. Certain of ACE s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other ACE full requirements contracts are not derivatives.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading activities, which included settled physical sales volumes of 1,506 GWhs and 4,015 GWhs for the three and nine months ended September 30, 2016, respectively, and 1,913 GWhs and 5,378 GWhs for the three and nine months ended September 30, 2015, respectively, are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s revenue from energy marketing activities. ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes.

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

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At September 30, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had $672 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately $5 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2016. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of September 30, 2016.

	Generation					Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[a]	Collateral and Netting[b]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$	$ 15	$ 4	$ (10)	$ 9	$	$ 9
Mark-to-market derivative assets (noncurrent assets)		13	4	(11)	6	39	45
Total mark-to-market derivative assets		28	8	(21)	15	39	54
Mark-to-market derivative liabilities (current liabilities)	(8)	(10)	(3)	12	(9)		(9)
Mark-to-market derivative liabilities (noncurrent liabilities)	(10)	(9)	(3)	12	(10)		(10)
Total mark-to-market derivative liabilities	(18)	(19)	(6)	24	(19)		(19)

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

126

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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

	Generation					Exelon Corporate	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading[(a)]**	**Collateral and Netting[(b)]**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (current assets)	$	$ 10	$ 10	$ (5)	$ 15	$	$ 15
Mark-to-market derivative assets (noncurrent assets)		10	5	(1)	14	25	39
Total mark-to-market derivative assets		20	15	(6)	29	25	54
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(9)	11	(8)		(8)
Mark-to-market derivative liabilities (noncurrent liabilities)	(8)	(1)	(3)	4	(8)		(8)
Total mark-to-market derivative liabilities	(16)	(3)	(12)	15	(16)		(16)
Total mark-to-market derivative net assets (liabilities)	$ (16)	$ 17	$ 3	$ 9	$ 13	$ 25	$ 38

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

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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

Table of Contents

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

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

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

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

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

Cash Flow Hedges. During the second quarter of 2016, Exelon entered into $90 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with an anticipated debt issuance. The swaps were designated as cash flow hedges. Exelon terminated the swaps during the third quarter of 2016 upon issuance of the debt. Exelon did not recognize a gain or loss as a result of the termination.

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

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

During the third quarter of 2014, ExGen Texas Power, LLC, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowing. See Note 14 Debt and Credit Agreements of the Exelon 2015 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $496 million as of September 30, 2016 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At September 30, 2016, the subsidiary had a $15 million derivative liability related to the swap.

During the first quarter of 2014, ExGen Renewables I, LLC, a subsidiary of Generation, entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2015 Form 10-K for additional information regarding the financing. The swaps have a notional amount of $176 million as of September 30, 2016 and expire in 2020. The swaps are designated as cash flow hedges. At September 30, 2016, the subsidiary had a $3 million derivative liability related to the swaps.

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

During the three and nine months ended September 30, 2016 and 2015, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships was immaterial.

Economic Hedges. During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2015 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the issuance of debt, Generation terminated the swaps. The total notional amount of the swaps were $25 million. No gain or loss was recognized as a result of the termination of the swaps.

During the third quarter of 2012, Constellation Solar Horizons, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 14 Debt and Credit Agreements of the Exelon 2015 Form 10-K for additional information regarding the financing. During the first quarter of 2016, upon the issuance of debt, Generation terminated the swap. The total notional amount of the swap was $24 million. No gain or loss was recognized as a result of the termination of the swap.

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

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

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

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation s use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e. to BB+ or Ba1). In the table below, Generation s energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including initial margin on exchange positions, is aggregated in the collateral and netting column. As of September 30, 2016 and December 31, 2015, $5 million and $3 million of cash collateral held and posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

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

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

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

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 September 30, 2016:

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

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of $135 million and $84 million, respectively, and current and noncurrent liabilities are shown net of collateral of $156 million and $110 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $485 million at September 30, 2016.

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

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

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 December 31, 2015:

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

(a) Exelon, Generation, PHI and DPL net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit and other forms of non-cash collateral. These are not reflected in the table above.

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

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

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

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

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 nine months ended September 30, 2016 and 2015, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from AOCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2016	**Income Statement Location**	**Total Cash Flow Hedges**	**Total Cash Flow Hedges**
AOCI derivative loss at June 30, 2016		$ (25)	$ (26)
Effective portion of changes in fair value		1	3
AOCI derivative loss at September 30, 2016		$ (24)	$ (23)

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps (treasury) to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. For the three and nine months ended September 30, 2016 and 2015, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in Operating revenues or Purchased power and fuel expense, or Interest expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

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

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 2016 and 2015, Exelon and Generation recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) before income taxes relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate and foreign exchange derivative contracts to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income and are included in Net fair value changes related to derivatives in Exelon s and Generation s Consolidated Statements of Cash Flows. In the tables below, Change in fair value represents the change in fair value of the derivative contracts held at the reporting date. The Reclassification to realized at settlement represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Change in fair value of commodity positions	$ 4	$ (4)	$ 18	$ 5
Reclassification to realized at settlement of commodity positions	(6)	(2)	(17)	(8)
Net commodity mark-to-market gains (losses)	(2)	(6)	1	(3)
Change in fair value of treasury positions		3	(2)	7
Reclassification to realized at settlement of treasury positions	1	(3)	2	(9)
Net treasury mark-to-market gains (losses)	1			(2)
Total net mark-to-market gains (losses)	$ (1)	$ (6)	$ 1	$ (5)

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 September 30, 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 $24 million, $45 million, $22 million, $47 million, $12 million, and $10 million as of September 30, 2016, respectively.

Rating as of September 30, 2016	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,017	$ 4	$ 1,013	1	$ 355
Non-investment grade	175	22	153		
No external ratings					
Internally rated investment grade	423	3	420		
Internally rated non-investment grade	61	3	58		
Total	$ 1,676	$ 32	$ 1,644	1	$ 355

Net Credit Exposure by Type of Counterparty	As of September 30, 2016
Financial institutions	$ 117
Investor-owned utilities, marketers, power producers	757
Energy cooperatives and municipalities	712
Other	58
Total	$ 1,644

(a) As of September 30, 2016, credit collateral held from counterparties where Generation had credit exposure included $10 million of cash and $22 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd s power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd s net credit exposure. As of September 30, 2016, ComEd s net credit exposure to suppliers was approximately $1 million.

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

PECO s supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements

137

with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. The unsecured credit used by the suppliers represents PECO s net credit exposure. As of September 30, 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 September 30, 2016, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 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 September 30, 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 September 30, 2016, BGE had credit exposure of less than $1 million related to off-system sales which is mitigated by parental guarantees, letters of credit or right to offset clauses within other contracts with those third-party suppliers.

Pepco s, DPL s and ACE s power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. The unsecured credit used by the suppliers represents Pepco s, DPL s and ACE s net credit exposure. As of September 30, 2016, Pepco s, DPL s and ACE s net credit exposures to suppliers were immaterial.

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 September 30, 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:

Credit-Risk Related Contingent Feature	September 30, 2016	December 31, 2015
Gross Fair Value of Derivative Contracts Containing this Feature[(a)]	$ (975)	$ (932)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[(b)]	664	684
Net Fair Value of Derivative Contracts Containing This Feature[(c)]	$ (311)	$ (248)

(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.

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 $501 million and letters of credit posted of $420 million and cash collateral held of $18 million and letters of credit held of $22 million as of September 30, 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 September 30, 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 September 30, 2016, Generation s swaps were in a liability position with a fair value of $4 million and Exelon s swaps were in an asset position, with a fair value of $35 million.

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 September 30, 2016, ComEd held $3 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd s annual renewable energy contracts, collateral postings are required to cover a fixed value 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 September 30, 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 September 30, 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 September 30, 2016, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2016, PECO could have been required to post approximately $25 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 September 30, 2016, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2016, BGE could have been required to post approximately $29 million of collateral to its counterparties.

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

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

DPL s natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of September 30, 2016, DPL could have been required to post an additional amount of approximately $9 million of collateral to its natural gas counterparties.

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

10. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

Exelon, 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 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 September 30, 2016 and December 31, 2015:

Commercial Paper Borrowings	September 30, 2016	December 31, 2015
ComEd	$ 10	$ 294
BGE		210
PHI Corporate		484
Pepco		64
DPL	17	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. 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%. On July 25, 2016, CENG paid off the outstanding balances under each note.

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 letters 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.

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

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 September 30, 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 Sheets. See Note 10 Debt of the PHI 2015 Form 10-K for additional information.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2016, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	2.45%	April 15, 2021	$300	Repay commercial paper issued by PHI and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	3.40%	April 15, 2026	$750	Repay commercial paper issued by PHI and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	4.45%	April 15, 2046	$750	Repay commercial paper issued by PHI and for general corporate purposes
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
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 86	Albany Green Energy biomass generation development
Generation	Energy Efficiency Project Financing	3.17%	December 31, 2017	$ 16	Funding to install energy conservation measures in Brooklyn, NY
Generation	Energy Efficiency Project Financing	3.42%	January 31, 2018	$ 13	Funding to install energy conservation measures for the Naval Station Great Lakes project
ComEd	First Mortgage Bonds, Series 120	2.55%	June 15, 2026	$500	Refinance maturing mortgage bonds, repay a portion of ComEd s outstanding commercial paper obligations and for general corporate purposes

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
ComEd	First Mortgage Bonds, Series 121	3.65%	June 15, 2046	$700	Refinance maturing mortgage bonds, repay a portion of ComEd s outstanding commercial paper obligations and for general corporate purposes
Generation	Energy Efficiency Project Financing	3.52%	April 30, 2018	$ 11	Funding to install energy conservation measures for the Smithsonian Zoo project
Pepco	Energy Efficiency Project Financing	3.30%	December 15, 2017	$ 2	Funding to install energy conservation measures for the DOE Germantown project
BGE	Notes	2.40%	August 15, 2026	$350	Redeem the $190M of outstanding preference shares and for general corporate purposes
BGE	Notes	3.50%	August 15, 2046	$500	Redeem the $190M of outstanding preference shares and for general corporate purposes
PECO[(a)]	First Mortgage Bonds	1.70%	September 15, 2021	$300	Refinance maturing mortgage bonds
Generation	SolGen Nonrecourse Debt	3.93%	September 30, 2036	$150	General corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.25%	September 18, 2019	$ 4	General corporate purposes for EGTP

(a) Includes restricted proceeds of $30 million shown in the Restricted proceeds from issuance of long-term debt on Exelon s and PECO s Cash Flow Statements and Restricted cash and cash equivalents on Exelon s and PECO s Consolidated Balance Sheets. The restricted proceeds were used as a portion of the payment on the maturing mortgage bonds due October 15, 2016, and as of that date, the restriction is no longer in place.

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. The outstanding balance was classified as Long-term debt on Exelon s and Generation s Consolidated Balance Sheets.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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. On March 31, 2016, $7 million of the debt was repaid using CEU Holding s 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. At March 31, 2016, 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.

On June 16, 2016, CEU Holdings executed a forbearance agreement with the lenders which included terms stipulating roles and responsibilities governing a sales process, approval of the sale of the assets to be at the discretion of the lenders, and a sales timetable, with ultimate execution of the sales agreement expected to occur by December 31, 2016. Upon disposition of the assets and the satisfaction of certain other conditions, CEU Holdings will be released of its obligations regardless of the amount of asset sale proceeds received. 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, Note 5 Mergers, Acquisitions and Dispositions and Note 6 Impairment of Long-Lived Assets for additional information.

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 September 30, 2016								
						Successor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.8	2.6	7.3	2.4	5.2	5.6	5.6	5.2	6.1
Qualified nuclear decommissioning trust fund income	4.0	7.8							
Domestic production activities deduction									
Health care reform legislation									
Amortization of investment tax credit, net deferred taxes	(0.9)	(1.6)	(0.6)	(0.1)	(0.2)	(0.1)		(0.2)	(0.1)
Plant basis differences	(3.0)		(1.9)	(6.7)	(0.5)	(5.0)	(6.7)	(1.3)	(4.6)
Production tax credits and other credits	(2.9)	(5.7)	(0.1)						
Noncontrolling interests	0.2	0.5							
Statute of limitations expiration	(0.1)	0.3							
Penalties	4.3		27.2						
Merger expenses	(0.6)					(5.7)	(2.3)	(8.6)	(2.9)
Other	(0.8)	(0.5)	0.1	0.1	(0.4)	(0.7)	(0.9)	0.1	(0.6)
Effective income tax rate	39.0%	38.4%	67.0%	30.7%	39.1%	29.1%	30.7%	30.2%	32.9%

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30, 2015								
						Predecessor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	2.7	2.1	5.0	1.2	5.3	6.2	4.8	7.4	5.4
Qualified nuclear decommissioning trust fund income	(5.4)	(12.5)							
Domestic production activities deduction	(4.9)	(11.6)							
Health care reform legislation					0.2				
Amortization of investment tax credit, net deferred taxes	(2.3)	(5.2)	(0.3)	(0.1)	(0.2)	(0.2)	(0.1)	(0.6)	(0.3)
Plant basis differences	(1.4)		(0.1)	(7.0)	(0.6)	(3.7)	(3.5)	(3.5)	(3.1)
Production tax credits and other credits	(3.8)	(9.0)				(1.2)			
Noncontrolling interests	1.7	3.9							
Statute of limitations expiration	(6.4)	(15.2)							
Other	1.2	0.4	0.3		(0.4)	(1.1)	(1.4)	(0.8)	1.9
Effective income tax rate	16.4%	(12.1)%	39.9%	29.1%	39.3%	35.0%	34.8%	37.5%	38.9%

146

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Nine Months Ended September 30, 2016								*Successor* March 24, 2016 to September 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL[(a)]	ACE[(a)]	PHI[(a)]	PHI
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:										
State income taxes, net of Federal income tax benefit[(b)]	2.5	2.6	5.4	1.3	4.8	23.0	310.5	5.5	4.4	11.9
Qualified nuclear decommissioning trust fund income	4.8	8.8								
Domestic production activities deduction										
Health care reform legislation										
Amortization of investment tax credit, including deferred taxes on basis difference	(1.3)	(2.0)	(0.3)	(0.1)	(0.2)	(0.2)	(17.9)	0.5	0.5	(0.9)
Plant basis differences	(4.5)		(0.6)	(8.8)	(3.3)	(29.0)	(98.6)	7.8	17.5	(13.5)
Production tax credits and other credits	(4.1)	(7.6)								
Noncontrolling interests	0.5	0.9								
Statute of limitations expiration	(0.5)	(1.7)								
Penalties	2.3		5.6							
Merger expenses	6.2					36.7	635.9	(35.4)	(49.8)	11.1
Other[(c)]	(1.8)	(2.1)		(1.5)		(2.5)	35.1	0.4	1.4	3.6
Effective income tax rate	39.1%	33.9%	45.1%	25.9%	36.3%	63.0%	900.0%	13.8%	9.0%	47.2%

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Nine Months Ended September 30, 2015								
						Predecessor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	3.1	2.8	5.2	1.2	5.3	7.1	4.6	6.1	5.5
Qualified nuclear decommissioning trust fund income	(0.9)	(1.6)							
Domestic production activities deduction	(2.8)	(4.9)							
Health care reform legislation					0.2				
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(1.9)	(0.3)	(0.1)	(0.1)	(0.3)	(0.1)	(0.4)	(0.5)
Plant basis differences	(1.2)		(0.1)	(7.3)	(0.4)	(5.0)	(6.2)	(2.0)	(2.5)
Production tax credits and other credits	(2.2)	(3.8)				(1.9)			
Noncontrolling interests		0.1							
Statute of limitations expiration	(1.6)	(2.9)							
Other	0.9	0.6	0.2	0.2	(0.1)	(0.1)	(0.7)	(0.5)	0.8
Effective income tax rate	29.1%	23.4%	40.0%	29.0%	39.9%	34.8%	32.6%	38.2%	38.3%

(a) DPL and ACE recognized a loss before income taxes for the nine months ended September 30, 2016, and PHI recognized a loss before income taxes for the period of March 24, 2016, through September 30, 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.
(c) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.

Accounting for Uncertainty in Income Taxes

The Registrants have the following unrecognized tax benefits as of September 30, 2016 and December 31, 2015:

						Successor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
September 30, 2016	$ 937	$ 516	$ (12)	$	$ 120	$ 157	$ 79	$ 34	$ 22

						Predecessor			
	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 September 30, 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 $164 million, $135 million, $71 million, $31 million and $22 million, respectively.

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

Settlement of Income Tax Audits and Litigation

As of September 30, 2016, Exelon, Generation, BGE, PHI, Pepco, and DPL have approximately $251 million, $52 million, $120 million, $79 million, $59 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 $52 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefits related to BGE, DPL, and a portion of Pepco, if recognized, may be included in future regulated base rates and that portion would have no impact to the effective tax rate.

Other Income Tax Matters

Like-Kind Exchange (Exelon and ComEd)

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

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

In accordance with applicable accounting standards, Exelon was required to assess whether it was more-likely-than-not that to prevail in litigation. In light of the outcome of another case involving a listed transaction and Exelon s determination that settlement was unlikely, Exelon concluded that subsequent to December 31, 2012, it was no longer more-likely-than-not that its position would be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately $265 million, which represented 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 has agreed to hold ComEd harmless from any unfavorable impacts on ComEd s equity of the after-tax interest or penalty amounts. As a result, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a $172 million receivable and non-cash equity contributions from Exelon. Based on applicable case law and the facts of the transaction, Exelon did not believe it was likely a penalty would be assessed. Accordingly, no charge was recorded for the penalty asserted nor for after-tax interest that could be due on the asserted penalty.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

On September 19, 2016, the Tax Court rejected Exelon s position in the case and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon s evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest due on the asserted penalty. In early 2017, Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit.

While it has strong arguments on appeal with respect to both the merits and the penalty, Exelon has determined that, pursuant to accounting standards, it is no longer more-likely-than-not to avoid the penalty. As a result, in the third quarter of 2016, Exelon recorded a charge to earnings for the penalty and the after-tax interest due on the asserted penalty of approximately $200 million, of which approximately $150 million was recorded at ComEd. Exelon and ComEd recorded the penalty and interest due on the asserted penalty to Other, net and Interest expense, net, respectively, on their Consolidated Statements of Operations. Consistent with Exelon s agreement to continue to hold ComEd harmless from any unfavorable impact on its equity, ComEd recorded on its consolidated balance sheet as of September 30, 2016, a $150 million receivable and non-cash equity contributions from Exelon.

In order to appeal the decision, Exelon is required to pay the tax, penalties and interest at the time Exelon files its appeal (expected early 2017). While the final calculation of tax, penalties and interest has not yet been finalized by the IRS, Exelon estimates that a payment of approximately $1.4 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the first quarter of 2017. While Exelon will receive a tax benefit of $400 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. After taking into account these interest deduction tax benefits, the total estimated net cash outflow for the like-kind exchange is $1 billion, of which approximately $300 million is attributable to ComEd after giving consideration to Exelon s agreement to hold ComEd harmless from any unfavorable impacts of after-tax interest or penalty amounts on ComEd s equity. Upon a final appellate decision, which could take up to several years, Exelon expects to receive $80 million related to final interest computations.

As of September 30, 2016, ComEd has a total receivable from Exelon pursuant to the hold harmless agreement of $345 million, which is included in Current Receivables from Affiliates on ComEd s Consolidated Balance Sheet. Under the agreement, Exelon will settle this receivable with ComEd no later than the time that the payments related to the like-kind exchange are due to the IRS, currently anticipated in first quarter 2017. Exelon will not seek recovery from ComEd customers for any interest or penalty amounts associated with the like-kind exchange tax position.

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

Long-Term State Tax Apportionment (Exelon, Generation and PHI)

Exelon, Generation and PHI periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of their respective deferred state income taxes. Events that may require Exelon, Generation and PHI to update their long-term state tax apportionment include significant changes in tax law and/or significant operational changes, 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.

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

12. Nuclear Decommissioning (Exelon and Generation)

Nuclear Decommissioning Asset Retirement Obligations

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon s and Generation s Consolidated Balance Sheets from December 31, 2015 to September 30, 2016:

Nuclear decommissioning ARO at December 31, 2015[(a)]	$ 8,246
Accretion expense	325
Net increase due to changes in, and timing of, estimated cash flows	444
Costs incurred to decommission retired plants	(6)
Nuclear decommissioning ARO at September 30, 2016[(a)]	$ 9,009

(a) Includes $44 million and $7 million for the current portion of the ARO at September 30, 2016 and December 31, 2015, respectively, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets.

During the nine months ended September 30, 2016, Generation s nuclear ARO increased by approximately $763 million, reflecting impacts of ARO updates completed during the first and second quarters of 2016 to reflect changes in amounts and timing of estimated decommissioning cash flows and impacts of year-to-date accretion of the ARO liability due to the passage of time.

In 2016, the ARO liability increased by $444 million primarily driven by an increase of $384 million associated with the June 2, 2016 announcement to early retire the Clinton and Quad Cities nuclear units on June 1, 2017 and June 1, 2018, respectively, as well as an increase of $60 million primarily due to an increase in the estimated costs to decommission the Oyster Creek nuclear unit as a result of the completion of an updated decommissioning cost study. Refer to Note 7 Early Nuclear Plant Retirements for additional information regarding the announced early retirements of Clinton and Quad Cities. The increase in the ARO liability for Clinton and Quad Cities incorporates the early shutdown dates (including fleet-wide impacts of spent nuclear fuel removal and storage costs), increases in the assumed probabilities of longer term decommissioning scenarios, and reflects an increase in the estimated costs to decommission based on updated decommissioning cost studies reflecting the early retirement of these units.

The financial statement impact related to the increase in the ARO liability 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. The majority of the increase in cost will be amortized over the remaining useful lives of the Clinton, Quad Cities and Oyster Creek nuclear plants, which are set to retire in 2017, 2018 and 2019, respectively.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nuclear Decommissioning Trust Fund Investments

At September 30, 2016 and December 31, 2015, Exelon and Generation had NDT fund investments totaling $11,076 million and $10,342 million, respectively.

The following table provides unrealized gains on NDT funds for the three and nine months ended September 30, 2016 and 2015:

	Exelon and Generation		Exelon and Generation	
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Net unrealized gains (losses) on decommissioning trust funds Regulatory Agreement Units[(a)]	$ 155	$ (301)	$ 286	$ (385)
Net unrealized gains (losses) on decommissioning trust funds Non-Regulatory Agreement Units[(b)(c)]	116	(218)	216	(274)

(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 $(5) million of net unrealized gain related to the Zion Station pledged assets for the three months ended September 30, 2016. Excludes $(2) million and $9 million of net unrealized gain related to the Zion Station pledged assets for the nine months ended September 30, 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Station decommissioning within Generation s and Exelon s Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a Payable for Zion Station decommissioning in Generation s and Exelon s Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, are recorded as a change in the Payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Generation has retained its obligation for the SNF. Following ZionSolutions completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately $87 million which is included within the nuclear decommissioning ARO at September 30, 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 September 30, 2016 and December 31, 2015:

	Exelon and Generation	
	September 30, 2016	December 31, 2015
Carrying value of Zion Station pledged assets	$ 135	$ 206
Payable to Zion Solutions[(a)]	124	189
Current portion of payable to Zion Solutions[(b)]	91	99
Cumulative withdrawals by Zion Solutions to pay decommissioning costs[(c)]	855	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 Units 1 and 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. 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.

Generation will file its next decommissioning funding status report with the NRC by March 31, 2017. This report will reflect the status of decommissioning funding assurance as of December 31, 2016 and will reflect the impacts of the announced early retirements of Clinton and Quad Cities. A shortfall could require Exelon to post parental guarantees for Generation s share of the funding assurance. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward.

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 of PHI s defined benefit pension and other postretirement benefit plans, and assumed PHI s benefit plan obligations and related assets. As a result, PHI s benefit plan net obligation and related regulatory assets were transferred to Exelon. The legacy PHI pension and other postretirement benefit plans were initially 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. Exelon updated these amounts in June 2016 to reflect assumptions at March 31, 2016. The updated valuation resulted in a $25 million reduction in the net obligation.

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 3.96% 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 3.80%.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon s net periodic benefit costs, prior to capitalization, for the three and nine months ended September 30, 2016 and 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2016	2015	2016	2015
Components of net periodic benefit cost:				
Service cost	$ 92	$ 82	$ 27	$ 30
Interest cost	215	178	47	42
Expected return on assets	(293)	(257)	(42)	(38)
Amortization of:				
Prior service cost (benefit)	3	3	(48)	(43)
Actuarial loss	142	142	18	20
Net periodic benefit cost	$ 159	$ 148	$ 2	$ 11

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2016[(a)]	2015	2016[(a)]	2015
Components of net periodic benefit cost:				
Service cost	$ 262	$ 245	$ 80	$ 89
Interest cost	616	533	138	125
Expected return on assets	(847)	(770)	(121)	(113)
Amortization of:				
Prior service cost (benefit)	10	10	(138)	(130)
Actuarial loss	411	427	47	60
Net periodic benefit cost	$ 452	$ 445	$ 6	$ 31

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

	Predecessor PHI					
	Pension Benefits			Other Postretirement Benefits		
	January 1, 2016 to March 23, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015	January 1, 2016 to March 23, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
Components of net periodic benefit cost:						
Service cost	$ 12	$ 15	$ 43	$ 1	$ 2	$ 5
Interest cost	26	28	82	6	6	18

Expected return on assets	(30)	(35)	(105)	(5)	(6)	(17)
Amortization of:						
Prior service cost (benefit)			1	(3)	(3)	(9)
Actuarial loss	14	16	49	2	2	6
Net periodic benefit cost	$ 22	$ 24	$ 70	$ 1	$ 1	$ 3

The amounts below represent Exelon s, Generation s, ComEd s, PECO s, BGE s, PHI s, Pepco s, DPL s, ACE s, BSC s and PHISCO s allocated p of the pension and postretirement benefit plan costs, which were included in Property, plant and equipment within the respective Consolidated Balance Sheets and Operating and maintenance expense within the Consolidated Statement of Operations and Comprehensive Income during the three and nine months ended September 30, 2016 and 2015.

155

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Pension and Other Postretirement Benefit Costs	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon	$ 161	$ 159	$ 458	$ 476
Generation	54	67	163	200
ComEd	41	52	124	155
PECO	8	10	25	29
BGE	17	16	51	49
BSC[(a)]	13	14	37	43
Pepco[(b)]	8	7	24	22
DPL[(b)]	4	3	13	11
ACE[(b)]	4	3	11	11
PHISCO[(a)(b)]	12	12	33	29

Pension and Other Postretirement Benefit Costs	*Successor* Three Months Ended September 30, 2016	*Predecessor* Three Months Ended September 30, 2015	*Successor* March 24, 2016 to September 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016	*Predecessor* Nine Months Ended September 30, 2015
PHI	$ 28	$ 25	$ 58	$ 23	$ 73

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

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

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and nine months ended September 30, 2016 and 2015:

Savings Plan Matching Contributions	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon	$ 51	$ 51	$ 107	$ 111
Generation	31	27	56	60
ComEd	10	10	23	23
PECO	3	3	7	7
BGE	2	5	5	10
BSC[(a)]	2	6	9	11
Pepco[(b)]			2	2
DPL[(b)]	1	1	2	2
ACE[(b)]			1	1
PHISCO[(a)(b)]	2	2	5	5

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Savings Plan Matching Contributions	*Successor* Three Months Ended September 30, 2016	*Predecessor* Three Months Ended September 30, 2015	*Successor* March 24, 2016 to September 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016	*Predecessor* Nine Months Ended September 30, 2015
PHI	$ 3	$ 3	$ 7	$ 3	$ 10

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

14. Severance (All Registrants)

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

Ongoing Severance Plans

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

For the three and nine months ended September 30, 2016 and 2015, Exelon, Generation, ComEd and PHI recorded the following severance costs (benefits) associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income.

	Exelon	Generation[(a)]	ComEd[(a)]	*Successor* PHI
Three Months Ended				
September 30, 2016	$ 8	$ 7	$	$ 1
September 30, 2015	(3)	(3)		
Nine Months Ended				
September 30, 2016	$ 12	$ 10	$ 1	$ 1
September 30, 2015	18	17	1	

(a) The amounts above for Generation include less than $1 million for amounts billed by BSC through intercompany allocations for both the three months ended September 30, 2016 and 2015, and $2 million for both the nine months ended September 30, 2016 and 2015. The amounts above for ComEd include $1 million billed by BSC through intercompany allocations for both the nine months ended

September 30, 2016 and 2015. The amounts above for PHI include $1 million billed by BSC through intercompany allocations for the three and nine months ended September 30, 2016.

Early Plant Retirement-Related Severance

As a result of the Clinton and Quad Cities plant retirement decision, Exelon and Generation will incur certain employee-related costs, including severance benefit costs. Severance benefits will be provided to

157

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

impacted union and non-union employees, to the extent that those employees are not redeployed to other locations. The final amount of severance cost will ultimately depend on the specific employees severed.

For the three and nine months ended September 30, 2016, the Registrants recorded the following severance costs (benefits) related to the early plant retirements within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation[(a)]
Three Months Ended		
September 30, 2016	$ (2)	$ (2)
Nine Months Ended		
September 30, 2016	$ 44	$ 44

(a) The amounts above for Generation include $2 million for amounts billed by BSC through intercompany allocations for the nine months ended September 30, 2016.

Cost Management Program-Related Severance

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

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. Additional severance benefit costs recorded in the third quarter were $1 million for Generation and Exelon. The final amount of the charge will ultimately depend on the specific employees severed.

For the nine months ended September 30, 2016, the Registrants recorded the following severance costs related to the cost management program within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income, pursuant to the authoritative guidance for ongoing severance plans:

	Exelon	Generation	ComEd	PECO	BGE
Nine Months Ended September 30, 2016					
Severance benefits[(a)]	$ 18	$ 13	$ 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 nine months ended September 30, 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. Cash payments under the plan began in May 2016 and will continue through 2020.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco[(b)]	DPL[(c)]	ACE
Nine Months Ended September 30, 2016									
Severance benefits[(a)]	$ 55	$ 9	$ 2	$ 1	$ 1	$ 42	$ 20	$ 12	$ 10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE include amounts billed by BSC and/or PHISCO through intercompany allocations of $8 million, $2 million, $1 million, $1 million, $19 million, $11 million and $10 million for the nine months ended September 30, 2016.
(b) Pepco established a regulatory asset of $10 million as of September 30, 2016, primarily for severance benefit costs related to the PHI merger.
(c) DPL established a regulatory asset of $3 million as of September 30, 2016, primarily for severance benefit costs related to the PHI merger.

Severance Liability

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

Severance Liability	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Balance at December 31, 2015	$ 35	$ 23	$ 3	$	$ 1	$	$	$	$
Severance charges[(a)(b)]	136	63	1			53	1	1	
Payments	(39)	(7)	(1)		(1)	(25)	(1)	(1)	
Balance at September 30, 2016	$ 132	$ 79	$ 3	$	$	$ 28	$	$	$

(a) Includes salary continuance and health and welfare severance benefits. Amounts primarily represent benefits provided for the PHI post-merger integration, the Clinton and Quad Cities early plant retirements and the cost management program.
(b) Represents activity from March 24, 2016 to September 30, 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 nine months ended September 30, 2016 and 2015:

Nine Months Ended September 30, 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
Exelon[a]						
Beginning balance	$ (19)	$ 3	$ (2,565)	$ (40)	$ (3)	$ (2,624)
OCI before reclassifications	(1)		(2)	3	(5)	(5)
Amounts reclassified from AOCI[b]	(3)		104	5		106
Net current-period OCI	(4)		102	8	(5)	101
Ending balance	$ (23)	$ 3	$ (2,463)	$ (32)	$ (8)	$ (2,523)
Generation[a]						
Beginning balance	$ (21)	$ 1	$	$ (40)	$ (3)	$ (63)
OCI before reclassifications		1		3	1	5
Amounts reclassified from AOCI[b]	(3)			5		2
Net current-period OCI	(3)	1		8	1	7
Ending balance	$ (24)	$ 2	$	$ (32)	$ (2)	$ (56)
PECO[a]						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI[b]						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1
PHI Predecessor[a]						
Beginning balance January 1, 2016	$ (8)	$	$ (28)	$	$	$ (36)
OCI before reclassifications						

Amounts reclassified from AOCI(b)			1			1
Net current-period OCI			1			1
Ending balance March 23, 2016(c)	$ (8)	$	$ (27)	$	$	$ (35)

160

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 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
Exelon[a]						
Beginning balance	$ (28)	$ 3	$ (2,640)	$ (19)	$	$ (2,684)
OCI before reclassifications	(18)		(29)	(17)		(64)
Amounts reclassified from AOCI[b]	22		130			152
Net current-period OCI	4		101	(17)		88
Ending balance	$ (24)	$ 3	$ (2,539)	$ (36)	$	$ (2,596)
Generation[a]						
Beginning balance	$ (18)	$ 1	$	$ (19)	$	$ (36)
OCI before reclassifications	(13)			(17)		(30)
Amounts reclassified from AOCI[b]	6					6
Net current-period OCI	(7)			(17)		(24)
Ending balance	$ (25)	$ 1	$	$ (36)	$	$ (60)
PECO[a]						
Beginning balance	$	$ 1	$	$	$	$ 1
OCI before reclassifications						
Amounts reclassified from AOCI[b]						
Net current-period OCI						
Ending balance	$	$ 1	$	$	$	$ 1
PHI Predecessor[a]						
Beginning balance	$ (9)	$	$ (37)	$	$	$ (46)
OCI before reclassifications						
Amounts reclassified from AOCI[b]	1		4			5
Net current-period OCI	1		4			5
Ending balance	$ (8)	$	$ (33)	$	$	$ (41)

(a) All amounts are net of tax and noncontrolling interest. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) 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 and nine months ended September 30, 2016 and 2015. The following tables present amounts reclassified out of AOCI to Net income for Exelon, Generation and PHI during the three and nine months ended September 30, 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 September 30, 2016

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Generation	Affected line item in the Statement of Operations and Comprehensive Income
Amortization of pension and other postretirement benefit plan items			
Prior service costs[(b)]	$ 19	$	
Actuarial losses[(b)]	(76)		
Total before tax	(57)		
Tax benefit	22		
Net of tax	$ (35)	$	
Gains (losses) on foreign currency translation			
Other	$ (5)	$ (5)	Other income and (deductions)
Total before tax	(5)	(5)	
Tax expense			
Net of tax	$ (5)	$ (5)	
Total Reclassifications for the period	$ (40)	$ (5)	Comprehensive income

Nine Months Ended September 30, 2016

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Generation	*Predecessor* January 1, 2016 to March 23, 2016 PHI	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges				
Other cash flow hedges	$ 5	$ 5	$	Interest expense
Total before tax	5	5		
Tax expense	(2)	(2)		

Net of tax	$	3	$	3	$			Comprehensive income
Amortization of pension and other postretirement benefit plan items								
Prior service costs[b]	$	57	$		$			
Actuarial losses[b]		(227)				(1)		
Total before tax		(170)				(1)		
Tax benefit		66						
Net of tax	$	(104)	$		$	(1)		
Gains (losses) on foreign currency translation								
Other	$	(5)	$	(5)	$			Other income and (deductions)
Total before tax		(5)		(5)				
Tax expense								
Net of tax	$	(5)	$	(5)	$			
Total Reclassifications	$	(106)	$	(2)	$	(1)		Comprehensive income

162

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three Months Ended September 30, 2015

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	*Predecessor* PHI	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges				
Other cash flow hedges	$ (4)	$ (4)	$ (1)	Interest expense
Total before tax	(4)	(4)	(1)	
Tax expense	1	1		
Net of tax	$ (3)	$ (3)	$ (1)	Comprehensive income
Amortization of pension and other postretirement benefit plan items				
Prior service costs[b]	$ 19	$	$	
Actuarial losses[b]	(90)		(2)	
Total before tax	(71)		(2)	
Tax expense	28		2	
Net of tax	$ (43)	$	$	
Total Reclassifications for the period	$ (46)	$ (3)	$ (1)	Comprehensive income

Nine Months Ended September 30, 2015

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	*Predecessor* PHI	Affected line item in the Statement of Operations and Comprehensive Income
Gains and (losses) on cash flow hedges				
Terminated interest rate swaps	$ (26)	$	$	Other, net
Energy related hedges	2	2		Operating revenues
Other cash flow hedges	(11)	(11)	(1)	Interest expense
Total before tax	(35)	(9)	(1)	
Tax benefit	13	3		
Net of tax	$ (22)	$ (6)	$ (1)	Comprehensive income

Amortization of pension and other postretirement benefit plan items							
Prior service costs(b)	$	57	$		$		
Actuarial losses(b)		(270)				(7)	
Total before tax		(213)				(7)	
Tax benefit		83				3	
Net of tax	$	(130)	$		$	(4)	
Total Reclassifications	$	(152)	$	(6)	$	(5)	Comprehensive income

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

163

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 7	$ 8	$ 22	$ 22
Actuarial loss reclassified to periodic cost	(29)	(35)	(88)	(105)
Pension and non-pension postretirement benefit plans valuation adjustment	1		1	17
Change in unrealized gain/(loss) on cash flow hedges	(1)	3	3	(3)
Change in unrealized loss on equity investments			3	
Change in unrealized gain on marketable securities	(1)		(1)	
Total	$ (23)	$ (24)	$ (60)	$ (69)
Generation				
Change in unrealized gain/(loss) on cash flow hedges	$ (2)	$ 3	$ 1	$ 4
Change in unrealized loss on equity investments			3	
Change in unrealized gain on marketable securities				
Total	$ (2)	$ 3	$ 4	$ 4

PHI	Three Months Ended September 30, 2015	*Predecessor* January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015
Pension and non-pension postretirement benefit plans:			
Actuarial loss reclassified to periodic cost	$ (2)	$	$ (3)

16. Mezzanine Equity (Exelon, Generation and PHI)

Contingently Redeemable Noncontrolling Interests (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 interests holder could be contingently redeemable. These circumstances are outside of the control of Generation and the noncontrolling interests holder resulting in a portion of the noncontrolling interests being considered contingently redeemable and thus presented in mezzanine equity on the consolidated balance sheet.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table summarizes the changes in the contingently redeemable noncontrolling interests for the nine months ended September 30, 2016:

Balance at December 31, 2015	$ 28
Cash received from noncontrolling interests	105
Release of contingency	(107)
Balance at September 30, 2016	$ 26

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 PHI s Consolidated Balance Sheets. 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, within PHI s predecessor period, January 1, 2016 to March 23, 2016, Consolidated Statements of Operations and Comprehensive Income.

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 and Equity (Exelon and BGE)
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 September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Exelon				
Net income attributable to common shareholders	$ 490	$ 629	$ 930	$ 1,959
Weighted average common shares outstanding basic	925	913	924	879

Assumed exercise and/or distributions of stock-based awards	2	2	2	4
Weighted average common shares outstanding diluted	927	915	926	883

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 11 million and 12 million for the three and nine months ended September 30, 2016, respectively and 14 million for three and nine months ended September 30, 2015. 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 less than 1 million for the three and nine months ended September 30, 2016, respectively, and 4 million and 2 million for the three and nine months ended September 30, 2015, respectively. 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 September 30, 2016. In 2008, Exelon management decided to defer indefinitely any share repurchases.

Preference Stock Redemption (BGE)

BGE had $190 million of cumulative preference stock that was redeemable at its option at any time after October 1, 2015 for the redemption price of $100 per share, plus accrued and unpaid dividends. On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.99% Cumulative Preference Stock, 1995 Series for $100 million, plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed the remaining 500,000 shares of its outstanding 6.970% Cumulative Preference Stock, 1993 Series and the remaining 400,000 shares of its outstanding 6.70% Cumulative Preference Stock, 1993 Series for $90 million, plus accrued and unpaid dividends.

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 $450 million to $550 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 September 30, 2016, Exelon and Generation have incurred $404 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.

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

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 commitments include 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 September 30, 2016, Generation s estimated commitments relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	Total
2016[(a)]	$ 79
2017	25
2018	4
Total	$ 108

(a) The noncontrolling interests holder of 2015 ESA Investco, LLC will contribute up to $31 million in support of a portion of the remaining equity commitment.

Commercial Commitments (All Registrants)

The Registrants commercial commitments as of September 30, 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)[(a)]	$ 1,720	$ 1,650	$ 16	$ 23	$ 2	$ 1	$	$	$ 1
Surety bonds[(b)]	1,084	984	10	9	11	16	9	4	3
Financing trust guarantees	628		200	178	250				
Nuclear insurance premiums[(c)]	3,045	3,045							
Guaranteed lease residual values[(d)]	20					20	6	7	5
Total commercial commitments	$ 6,497	$ 5,679	$ 226	$ 210	$ 263	$ 37	$ 15	$ 11	$ 9

(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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 $50 million, $13 million of which is a guarantee by Pepco, $17 million by DPL and $13 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 September 30, 2016, the current liability limit per incident is $13.4 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 September 30, 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 participation in a retrospective rating plan for power reactors (currently 102 reactors) resulting in an additional $13.0 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 $13.4 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.

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 2021.

- 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 2022.

- 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, all of which the remediation has been completed and approved by the MDE or the Delaware Department of Natural Resources and Environmental Control.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 September 30, 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:

September 30, 2016	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation[(a)]
Exelon	$ 427	$ 318
Generation	76	
ComEd	283	281
PECO	36	34
BGE	2	2
PHI (Successor)	30	1
Pepco	27	
DPL	2	1
ACE	1	

December 31, 2015	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation[(a)]
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.

During the third quarter of 2016, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. The results of the study resulted in a $7 million and $2 million increase to environmental liabilities and related regulatory assets for ComEd and PECO, respectively.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 approximately $13 million at September 30, 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 subsequently 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.

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. Pepco has established what it believes is an appropriate reserve for potential penalties which is included in the table above. Pepco does not expect the amount of such penalties above the financial reserve to have a material adverse effect on Exelon s, PHI s and Pepco s consolidated financial condition, results of operations or cash flows.

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 November 15, 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.

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. The current estimated cost of the landfill cover remediation for the site is approximately $90 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the supplemental feasibility study to the EPA for review. Since June 2012, the EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study, that are now scheduled to be completed in the fall of 2016 to enable the EPA to propose a remedy for public comment by the end of 2016. While the EPA has not yet formally announced a change in the schedule, the PRPs believe that the final supplemental feasibility study will not be completed until year-end 2016 and the EPA announcement of the proposed remedy will take place in the third quarter of 2017. Thereafter, the EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. 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 believes that a partial excavation remedy is reasonably possible, but does not currently have a basis to establish a reasonable estimate of the range of costs. Generation believes the likelihood that the EPA would require a complete excavation remedy is remote. The cost of a partial or complete excavation could have a material, unfavorable impact on Generation s and Exelon s future results of operations and cash flows.

During December 2015, the EPA took two actions related to the West Lake Landfill designed to abate what it termed as imminent and dangerous conditions at the landfill. The first involved installation by the PRPs of a non-combustible surface cover to protect against surface fires in areas where radiological materials are believed to have been disposed. Generation has accrued what it believes to be an adequate amount to cover its anticipated liability for this interim action. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 PRP s, 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 2017 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, 63 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 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 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.

68th 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 which are included in the table above 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. Generation currently estimates the remaining cost to close the site to be approximately $6 million which has been fully reserved and included in the table above as of September 30, 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 PRP s signed an Administrative Settlement Agreement and Order on Consent with the EPA which requires the PRP s 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, BGE cannot estimate the range of loss.

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 which included a site-wide investigation of soils, 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 and BGE anticipates completing the additional work requested by the end of the first quarter of 2017. BGE has established what it believes is an appropriate reserve based upon the investigation to date. The established reserve is included in the table above. 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 third 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.

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 an estimated liability for this issue has been accrued, which is included in the table above. As the remedial investigation proceeds and potential remedies are identified, it is possible that additional reserves could be established in amounts that could be material to PHI, Pepco and Pepco Energy Services. Pursuant to Exelon s March 2016 acquisition of PHI, Pepco Energy Services was transferred to Generation. The ultimate resolution of this matter is currently not expected to have any significant financial impact on Generation.

Anacostia River Tidal Reach. Contemporaneous with the Benning RI/FS being performed by Pepco and Pepco Energy Services, DOEE and certain federal agencies have been conducting a separate RI/FS focused on the entire tidal reach of the Anacostia River extending from just north of the Maryland-D.C. boundary line to the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 asked Pepco, along with parties responsible for other sites along the river, to participate in a Consultative Working Group to provide input into the process for future remedial actions addressing the entire tidal reach of the river and to ensure proper coordination with the other river cleanup efforts currently underway, including cleanup of the river segment adjacent to the Benning Road site resulting from the Benning Road RI/FS. Pepco responded that it will participate in the Consultative Working Group but its participation is not an acceptance of any financial responsibility beyond the work that will be performed at the Benning Road site described above. On September 13, 2016 PHI attended the first Consultative Working Group meeting along with several other possible private and governmental PRP s. At the meeting it was disclosed that the federal and DOEE authorities were conducting phase 2 of a remedial investigation, DOEE has targeted June 2018 as the date for remedy selection for clean-up of sediments in this section of the river. The Consultative Working Group and the other possible PRPs raised a number of issues with the proposed clean-up process and schedule. Several follow up meetings have been scheduled. At this time, it is not possible to predict the extent of Pepco s 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, which is included in the table above.

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 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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, Generation and PECO. 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 September 30, 2016 and December 31, 2015, Generation had reserved approximately $83 million and $95 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2016, approximately $22 million of this amount related to 237 open claims presented to Generation, while the remaining $61 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. During the nine months ended September 30, 2016, Generation decreased its reserve by approximately $8 million, primarily attributable to a continued decline in expected claims activity.

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,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee s last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court s ruling in November 2013, Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been 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. Since the Illinois Supreme Court s ruling in November 2015, Exelon, Generation, and ComEd have not experienced a significant increase in asbestos-related personal injury claims brought by former ComEd employees.

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, ComEd s, PECO and BGE 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 456 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. 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;
- 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 September 30, 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.

Deere Wind Energy Assets (Exelon and Generation)

In 2013, Deere & Company (Deere) filed a lawsuit against Generation in the Delaware Superior Court relating to Generation s acquisition of the Deere wind energy assets. Under the purchase agreement, Deere was entitled to receive earn-out payments if certain specific wind projects already under development in Michigan met certain development and construction milestones following the sale. In the complaint, Deere seeks to recover a $14 million earn-out payment associated with one such project, which was never completed. Generation has filed counterclaims against Deere for breach of contract, with a right of recoupment and set off. On June 2, 2016, the Delaware Superior Court entered summary judgment in favor of Deere. Generation is reviewing the decision and determining whether to appeal to the Delaware Supreme Court. Generation has accrued an amount to cover its potential liability.

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 11 Income Taxes for information regarding the Registrants income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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 and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30, 2016								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[(a)]									
Regulatory agreement units	$ 57	$ 57	$	$	$	$	$	$	$
Non-regulatory agreement units	35	35							
Net unrealized gains on decommissioning trust funds									
Regulatory agreement units	155	155							
Non-regulatory agreement units	116	116							
Net unrealized losses on pledged assets									
Zion Station decommissioning	(5)	(5)							
Regulatory offset to decommissioning trust fund-related activities[(b)]	(168)	(168)							
Total decommissioning-related activities	190	190							
Investment income	2	1		(1)					
Interest income related to uncertain income tax positions	8								
Penalty related to uncertain income tax positions[(c)]	(106)		(86)						
AFUDC Equity	19		5	2	5	7	5	1	1
Other	7	(6)	1	1		12	7	2	1
Other, net	$ 120	$ 185	$ (80)	$ 2	$ 5	$ 19	$ 12	$ 3	$ 2

	Nine Months Ended September 30, 2016								*Successor* March 24, 2016 to September 30, 2016	*Predecessor* January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Other, Net										
Decommissioning-related activities:										
Net realized income on decommissioning trust funds[(a)]										
Regulatory agreement units	$ 181	$ 181	$	$	$	$	$	$	$	$
Non-regulatory agreement units	95	95								
Net unrealized gains on decommissioning trust funds										
Regulatory agreement units	286	286								

Non-regulatory agreement units	216	216								
Net unrealized losses on pledged assets										
Zion Station decommissioning	(2)	(2)								
Regulatory offset to decommissioning trust fund-related activities[b]	(380)	(380)								
Total decommissioning-related activities	396	396								
Investment income (expense)	14	6		(1)	2[d]				1	
Long-term lease income	4									
Interest income related to uncertain income tax positions	13					1		1		
Penalty income related to uncertain income tax positions[c]	(106)		(86)							
AFUDC Equity	43		8	6	14	14	3	5	15	7
Loss on debt extinguishment	(3)	(2)								
Other	16	(5)	6	1		13	6	2	15	(11)
Other, net	$ 377	$ 395	$ (72)	$ 6	$ 16	$ 28	$ 9	$ 8	$ 31	$ (4)

180

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Three Months Ended September 30, 2015								
						Predecessor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[a]									
Regulatory agreement units	$ 39	$ 39	$	$	$	$	$	$	$
Non-regulatory agreement units	18	18							
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(301)	(301)							
Non-regulatory agreement units	(218)	(218)							
Regulatory offset to decommissioning trust fund-related activities[b]	207	207							
Total decommissioning-related activities	(255)	(255)							
Investment income (expense)	4	1		(1)	1[d]				
Long-term lease income	4								
AFUDC Equity	6		1	1	4	2	3		
Other	(3)	(3)	3	1	(1)	25	5	4	1
Other, net	$ (244)	$ (257)	$ 4	$ 1	$ 4	$ 27	$ 8	$ 4	$ 1

	Nine Months Ended September 30, 2015								
						Predecessor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Other, Net									
Decommissioning-related activities:									
Net realized income on decommissioning trust funds[a]									
Regulatory agreement units	$ 203	$ 203	$	$	$	$	$	$	$
Non-regulatory agreement units	122	122							
Net unrealized losses on decommissioning trust funds									
Regulatory agreement units	(385)	(385)							
Non-regulatory agreement units	(274)	(274)							
Net unrealized gains on pledged assets									
Zion Station decommissioning	9	9							
Regulatory offset to decommissioning trust fund-related activities[b]	129	129							
Total decommissioning-related activities	(196)	(196)							
Investment income (expense)	6	1		(1)	3[d]				
Long-term lease income	12								
Interest income related to uncertain income tax positions		1							1
AFUDC Equity	16		2	4	10	11	9	1	1
Terminated interest rate swaps[e]	(26)								
Other	9	1	12			37	12	7	2
Other, net	$ (179)	$ (193)	$ 14	$ 3	$ 13	$ 48	$ 21	$ 8	$ 4

(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) See Note 11 Income Taxes for discussion of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position.
(d) 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.
(e) 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following utility taxes are included in revenues and expenses for the three and nine months ended September 30, 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.

	Three Months Ended September 30, 2016								
						Successor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$ 255	$ 35	$ 67	$ 40	$ 21	$ 92	$ 87	$ 5	$

	Nine Months Ended September 30, 2016								*Successor*	*Predecessor*
									March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Utility taxes	$ 624	$ 90	$ 186	$ 106	$ 66	$ 240	$ 14	$	$ 176	$ 78

	Three Months Ended September 30, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$ 151	$ 28	$ 63	$ 37	$ 23	$ 86	$ 82	$ 4	$

	Nine Months Ended September 30, 2015								
						Predecessor			
	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Utility taxes	$ 430	$ 79	$ 180	$ 104	$ 67	$ 253	$ 239	$ 14	$

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants Consolidated Statements of Cash Flows for the nine months ended September 30, 2016 and 2015:

									Successor	*Predecessor*
	Nine Months Ended September 30, 2016								March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**PHI**	**PHI**
Depreciation, amortization, accretion and depletion										
Property, plant and equipment[a]	$ 2,490	$ 1,297	$ 524	$ 181	$ 223	$ 128	$ 82	$ 61	$ 215	$ 94
Amortization of regulatory assets[a]	293		49	20	84	93	38	69	140	58
Amortization of intangible assets, net[a]	38	32								
Amortization of energy contract assets and liabilities[b]	(7)	(7)								
Nuclear fuel[c]	862	862								
ARO accretion[d]	333	332	1							
Total depreciation, amortization, accretion and depletion	$ 4,009	$ 2,516	$ 574	$ 201	$ 307	$ 221	$ 120	$ 130	$ 355	$ 152

	Nine Months Ended September 30, 2015								
						Predecessor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Depreciation, amortization, accretion and depletion									
Property, plant and equipment[a]	$ 1,648	$ 739	$ 471	$ 179	$ 216	$ 292	$ 122	$ 76	$ 57
Amortization of regulatory assets[a]	131		57	19	55	182	69	37	78
Amortization of intangible assets, net[a]	39	35							
Amortization of energy contract assets and liabilities[b]	(20)	(19)							
Nuclear fuel[c]	841	841							
ARO accretion[d]	291	291							
Total depreciation, amortization, accretion and depletion	$ 2,930	$ 1,887	$ 528	$ 198	$ 271	$ 474	$ 191	$ 113	$ 135

(a) Included in Depreciation and amortization on the Registrants Consolidated Statements of Operations and Comprehensive Income.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Nine Months Ended September 30, 2016								*Successor*	*Predecessor*
									March 24, 2016 to September 30, 2016	**January 1, 2016 to March 23, 2016**
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**	**PHI**	**PHI**
Other non-cash operating activities:										
Pension and non-pension postretirement benefit costs	$ 458	$ 163	$ 124	$ 25	$ 50	$ 24	$ 13	$ 11	$ 58	$ 23
Loss from equity method investments	15	16								
Provision for uncollectible accounts	107	14	31	24	12	15	12	18	27	16
Stock-based compensation costs	88									3
Other decommissioning-related activity[(a)]	(237)	(237)								
Energy-related options[(b)]	(20)	(20)								
Amortization of regulatory asset related to debt costs	7		3	1		2		1	2	1
Amortization of rate stabilization deferral	62				62	3	3			5
Amortization of debt fair value adjustment	(9)	(9)								
Discrete impacts from EIMA[(c)]	(36)		(36)							
Amortization of debt costs	26	12	(3)	2	3					
Provision for excess and obsolete inventory	74	70	4			1	1	1		1
Merger-related commitments[(d)(e)]	508	3				125	73	110	308	
Severance costs	130	57							53	
Asset retirement costs							5	2		
Lower of cost or market inventory adjustment	36	36								
Other	15	24	(1)	(3)	(18)	(2)	(8)	(5)	(7)	(3)
Total other non-cash operating activities	$ 1,224	$ 129	$ 122	$ 49	$ 109	$ 168	$ 99	$ 138	$ 441	$ 46
Non-cash investing and financing activities:										
Change in capital expenditures not paid	$ (338)	$ (289)	$ (42)	$ (4)	$ 17	$ 15	$ (10)	$ 2	$ (5)	$ 11
Fair value of net assets contributed to Generation in connection with the PHI merger, net of cash[(d)(f)]		119								
Fair value of net assets distributed to Exelon in connection with the PHI Merger, net of cash [(d)(f)]									129	
Fair value of pension obligation transferred in connection with the PHI Merger									53	
Assumption of member purchase liability									29	
Assumption of merger commitment liability						33			33	
Change in PPE related to ARO update	476	476								
Indemnification of like-kind exchange position[(g)]			157							
Non-cash financing of capital projects	84	84								

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Nine Months Ended September 30, 2015								
						Predecessor			
	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Other non-cash operating activities:									
Pension and non-pension postretirement benefit costs	$ 476	$ 200	$ 155	$ 29	$ 49	$ 73	$ 22	$ 11	$ 11
Loss from equity method investments	3	4							
Provision for uncollectible accounts	114	15	46	37	15	49	15	18	15
Stock-based compensation costs	102					9			
Other decommissioning-related activity[(a)]	(31)	(31)							
Energy-related options[(b)]	18	18							
Amortization of regulatory asset related to debt costs						4	2		
Amortization of rate stabilization deferral	60				60	3	3	1	
Amortization of debt fair value adjustment	(34)	(9)							
Discrete impacts from EIMA[(c)]	101		101						
Amortization of debt costs	43	12	3	2	2	1			
Provision for excess and obsolete inventory	7	8				1			
Lower of cost or market inventory adjustment	15	15							
Other	(18)	(5)	7	1	(15)	3		1	1
Total other non-cash operating activities	$ 856	$ 227	$ 312	$ 69	$ 111	$ 143	$ 42	$ 31	$ 27
Non-cash investing and financing activities:									
Change in capital expenditures not paid	$ 59	$ 48	$ 62	$ (23)	$ (14)	$ (3)	$ (1)	$ 2	$
Nuclear fuel procurement[(d)]									
Change in PPE related to ARO update	811	811							
Indemnification of like-kind exchange position[(g)]			5						
Non-cash financing of capital projects	52	52							
Long-term software licensing agreement[(f)]	95								

(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 in Operating revenues.

(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 of such net assets to Generation.

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

185

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 September 30, 2016 and December 31, 2015:

September 30, 2016	Exelon	Generation	ComEd	PECO	BGE	*Successor* PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$ 18,354[(a)]	$ 10,004[(a)]	$ 3,841	$ 3,213	$ 3,198	$ 146	$ 3,026	$ 1,171	$ 1,008
Accounts receivable:									
Allowance for uncollectible accounts	$ 330	$ 85	$ 82	$ 78	$ 39	$ 46	$ 15	$ 14	$ 17

December 31, 2015	Exelon	Generation	ComEd	PECO	BGE	*Predecessor* PHI	Pepco	DPL	ACE
Property, plant and equipment:									
Accumulated depreciation and amortization	$ 16,375[(b)]	$ 8,639[(b)]	$ 3,710	$ 3,101	$ 3,016	$ 5,341	$ 2,929	$ 1,139	$ 968
Accounts receivable:									
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 $3,198 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 $16 million and $15 million as of September 30, 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 September 30, 2016 of $14 million consists of $0 million, $3 million and $11 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 September 30, 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.

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:

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.

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 and nine months ended September 30, 2016 and 2015 is as follows:

Three Months Ended September 30, 2016 and 2015

	Generation[(a)]	ComEd	PECO	BGE	*Successor* PHI[(b)]	Other[(c)]	Intersegment Eliminations	Exelon
Operating revenues[(d)]:								
2016								
Competitive businesses electric revenues	$ 4,322	$	$	$	$	$	$ (499)	$ 3,823
Competitive businesses natural gas revenues	326							326
Competitive businesses other revenues	387						(1)	386
Rate-regulated electric revenues		1,497	740	735	1,366		(8)	4,330
Rate-regulated natural gas revenues			48	77	17		(5)	137
Shared service and other revenues					11	362	(373)	
2015								
Competitive businesses electric revenues	$ 4,299	$	$	$	$	$	$ (204)	$ 4,095
Competitive businesses natural gas revenues	347							347
Competitive businesses other revenues	122							122
Rate-regulated electric revenues		1,376	691	655			(1)	2,721
Rate-regulated natural gas revenues			49	70			(3)	116
Shared service and other revenues						348	(348)	
Intersegment revenues[(e)]:								
2016	$ 500	$ 4	$ 2	$ 7	$ 11	$ 362	$ (885)	$ 1
2015	205	1	1	3		347	(555)	2
Net income (loss):								
2016	$ 271	$ 37	$ 122	$ 56	$ 166	$ (125)	$ (1)	$ 526
2015	332	149	90	54		(36)	(2)	587
Total assets:								
September 30, 2016	$ 47,568	$ 28,020	$ 11,041	$ 8,857	$ 21,063	$ 9,883	$ (11,897)	$ 114,535
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 September 30, 2016 include revenue from sales to PECO of $91 million and sales to BGE of $183 million in the Mid-Atlantic region, and sales to ComEd of $20 million in the Midwest region. For the three months ended September 30, 2015, intersegment revenues for Generation include revenue from sales to PECO of $61 million and sales to BGE of $141 million in the Mid-Atlantic region, and sales to ComEd of $2 million in the Midwest region. For the Successor period of three months ended September 30, 2016, intersegment revenues for Generation include revenue from sales to Pepco of $128 million, sales to DPL of $63 million, and sales to ACE of $15 million in the Mid-Atlantic region.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) Amounts included represent activity for PHI s successor period, three months ended September 30, 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 nine months ended September 30, 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 September 30, 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 September 30, 2016			Three Months Ended September 30, 2015		
	Revenues from external customers[a]	Intersegment revenues	Total Revenues	Revenues from external customers[a][c]	Intersegment revenues[c]	Total Revenues[c]
Mid-Atlantic	$ 1,813	$ (13)	$ 1,800	$ 1,640	$ (8)	$ 1,632
Midwest	1,163	1	1,164	1,152	(1)	1,151
New England	455	(4)	451	520		520
New York	331	(8)	323	254	(4)	250
ERCOT	289	6	295	317	(1)	316
Other Power Regions	271	(33)	238	416	(40)	376
Total Revenues for Reportable Segments	4,322	(51)	4,271	4,299	(54)	4,245
Other[b]	713	51	764	469	54	523
Total Generation Consolidated Operating Revenues	$ 5,035	$	$ 5,035	$ 4,768	$	$ 4,768

(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. Includes a $21 million decrease and $3 million decrease to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the three months ended September 30, 2016 and 2015, respectively, unrealized mark-to-market gains of $187 million and losses of $7 million for the three months ended September 30, 2016 and 2015, respectively, and elimination of intersegment revenues.
(c) Exelon corrected an error in the September 30, 2015 balances within Intersegment Revenue and Revenue from external customers for an overstatement of $54 million of Intersegment Revenue for Reportable Segments for the three months ended September 30, 2015, an understatement of Revenue from external customers for Reportable Segments of $54 million for the three months ended September 30, 2015, an understatement of $54 million of Intersegment Revenue for Other for the three months ended September 30, 2015, and an overstatement of Revenue from external customers for Other of $54 million for the three months ended September 30, 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 September 30, 2016			Three Months Ended September 30, 2015		
	RNF from external customers[a]	Intersegment RNF	Total RNF	RNF from external customers[a][c]	Intersegment RNF[c]	Total RNF[c]
Mid-Atlantic	$ 881	$ 6	$ 887	$ 979	$ 18	$ 997
Midwest	782	(1)	781	760	(4)	756
New England	170	(10)	160	148	(15)	133
New York	195	(1)	194	157	13	170
ERCOT	144	(51)	93	166	(55)	111
Other Power Regions	143	(66)	77	154	(71)	83
Total Revenues net of purchased power and fuel for Reportable Segments	2,315	(123)	2,192	2,364	(114)	2,250
Other[b]	131	123	254	(115)	114	(1)
Total Generation Revenues net of purchased power and fuel expense	$ 2,446	$	$ 2,446	$ 2,249	$	$ 2,249

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

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $22 million decrease and a $4 million decrease to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the three months ended September 30, 2016 and 2015, respectively, unrealized mark-to-market gains of $88 million and losses of $139 million for the three months ended September 30, 2016 and 2015, respectively, accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed in Note 7 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements of $28 million for the three months ended September 30, 2016, and the elimination of intersegment revenue net of purchased power and fuel expense.

(c) Exelon corrected an error in the September 30, 2015 balances within Intersegment RNF and RNF from external customers for an understatement of $12 million of Intersegment RNF for Reportable Segments for the three months ended September 30, 2015, and an overstatement of $12 million of Intersegment RNF for Other for the three months ended September 30, 2015. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of $13 million for the three months ended September 30, 2015. The error is not considered material to any prior period, and there is no net impact to Generation Total RNF for 2015.

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[b]	Intersegment Eliminations	PHI
Operating revenues[a]:							
Three months ended September 30, 2016	Successor						
Rate-regulated electric revenues		$ 635	$ 314	$ 421	$	$ (4)	$ 1,366
Rate-regulated natural gas revenues			17				17
Shared service and other revenues					11		11
Three months ended September 30, 2015	Predecessor						
Rate-regulated electric revenues		$ 592	$ 295	$ 386	$ 44	$	$ 1,317
Rate-regulated natural gas revenues			19				19
Shared service and other revenues							
Intersegment revenues[e]:							
Three months ended September 30, 2016	Successor	$ 1	$ 2	$ 1	$ 11	$ (4)	$ 11
Three months ended September 30, 2015	Predecessor	1	1	1		(3)	
Net income (loss):							
Three months ended September 30, 2016	Successor	$ 79	$ 44	$ 47	$ (15)	$ 11	$ 166
Three months ended September 30, 2015	Predecessor	60	15	22	(6)		91
Total assets:							
September 30, 2016	Successor	$ 7,219	$ 4,023	$ 3,507	$ 11,057	$ (4,743)	$ 21,063
December 31, 2015	Predecessor	6,908	3,969	3,387	7,162	(5,238)	16,188

(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 September 30, 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine Months Ended September 30, 2016 and 2015

	Generation[a]	ComEd	PECO	BGE	*Successor* PHI[b]	Other[c]	Intersegment Eliminations	Exelon
Operating revenues[d]:								
2016								
Competitive businesses electric revenues	$ 11,677	$	$	$	$	$	$ (1,118)	$ 10,559
Competitive businesses natural gas revenues	1,515							1,515
Competitive businesses other revenues	171						(2)	169
Rate-regulated electric revenues		4,031	1,971	1,998	2,485		(24)	10,461
Rate-regulated natural gas revenues			322	423	46		(10)	781
Shared service and other revenues					34	1,166	(1,199)	1
2015								
Competitive businesses electric revenues	$ 12,360	$	$	$	$	$	$ (564)	$ 11,796
Competitive businesses natural gas revenues	1,901							1,901
Competitive businesses other revenues	580						1	581
Rate-regulated electric revenues		3,709	1,950	1,908			(3)	7,564
Rate-regulated natural gas revenues			436	480			(12)	904
Shared service and other revenues						1,007	(1,007)	
Intersegment revenues[e]:								
2016	$ 1,121	$ 12	$ 5	$ 16	$ 34	$ 1,166	$ (2,351)	$ 3
2015	567	3	1	10		1,003	(1,581)	3
Net income (loss):								
2016	$ 556	$ 297	$ 346	$ 191	$ (91)	$ (340)	$ (3)	$ 956
2015	1,208	339	299	212		(96)	(3)	1,959

(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 nine months ended September 30, 2016 include revenue from sales to PECO of $234 million and sales to BGE of $489 million in the Mid-Atlantic region, and sales to ComEd of $38 million in the Midwest region. For the nine months ended September 30, 2015, intersegment revenues for Generation include revenue from sales to PECO of $173 million and sales to BGE of $376 million in the Mid-Atlantic region, and sales to ComEd of $17 million in the Midwest region. For the Successor period of March 24, 2016 to September 30, 2016, intersegment revenues for Generation include revenue from sales to Pepco of $223 million, sales to DPL of $109 million, and sales to ACE of $28 million in the Mid-Atlantic region.

(b) Amounts included represent activity for PHI s successor period, March 24, 2016 through September 30, 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 nine months ended September 30, 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 nine months ended September 30, 2016 and 2015.

193

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

(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:

	Nine Months Ended September 30, 2016			Nine Months Ended September 30, 2015		
	Revenues from external customers[a]	Intersegment revenues	Total Revenues	Revenues from external customers[a][c]	Intersegment revenues[c]	Total Revenues[c]
Mid-Atlantic	$ 4,776	$ (40)	$ 4,736	$ 4,560	$ (69)	$ 4,491
Midwest	3,330	13	3,343	3,634	(1)	3,633
New England	1,278	(6)	1,272	1,752	(6)	1,746
New York	906	(33)	873	783	(5)	778
ERCOT	659	6	665	691	(4)	687
Other Power Regions	728	(42)	686	940	(60)	880
Total Revenues for Reportable Segments	11,677	(102)	11,575	12,360	(145)	12,215
Other[b]	1,686	102	1,788	2,481	145	2,626
Total Generation Consolidated Operating Revenues	$ 13,363	$	$ 13,363	$ 14,841	$	$ 14,841

(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. Includes a $10 million decrease to revenues and a $19 million increase to revenues for the amortization of intangible assets and liabilities related to commodity contracts recorded at fair value for the nine months ended September 30, 2016 and 2015, respectively, unrealized mark-to-market losses of $366 million and gains of $171 million for the nine months ended September 30, 2016 and 2015, respectively, and elimination of intersegment revenues.

(c) Exelon corrected an error in the September 30, 2015 balances within Intersegment Revenue and Revenue from external customers for an overstatement of $144 million of Intersegment Revenue for Reportable Segments for the nine months ended September 30, 2015, an understatement of Revenue from external customers for Reportable Segments of $144 million for the nine months ended September 30, 2015, an understatement of $144 million of Intersegment Revenue for Other for the nine months ended September 30, 2015, and an overstatement of Revenue from external customers for Other of $144 million for the nine months ended September 30, 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:

	Nine Months Ended September 30, 2016			Nine Months Ended September 30, 2015		
	RNF from external customers[(a)]	Intersegment RNF	Total RNF	RNF from external customers[(a)(c)]	Intersegment RNF[(c)]	Total RNF[(c)]
Mid-Atlantic	$ 2,541	$ 15	$ 2,556	$ 2,679	$ (2)	$ 2,677
Midwest	2,225	4	2,229	2,220	(15)	2,205
New England	373	(23)	350	425	(46)	379
New York	607	(15)	592	462	40	502
ERCOT	335	(104)	231	344	(109)	235
Other Power Regions	357	(104)	253	341	(148)	193
Total Revenues net of purchased power and fuel expense for Reportable Segments	6,438	(227)	6,211	6,471	(280)	6,191
Other[(b)]	316	227	543	570	280	850
Total Generation Revenues net of purchased power and fuel expense	$ 6,754	$	$ 6,754	$ 7,041	$	$ 7,041

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

(b) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $15 million decrease to RNF and a $20 million increase to RNF for the amortization of intangible assets and liabilities related to commodity contracts for the nine months ended September 30, 2016 and 2015, respectively, unrealized mark-to-market losses of $113 million and gains of $258 million for the nine months ended September 30, 2016 and 2015, respectively, accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed in Note 7 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements of $38 million for the nine months ended September 30, 2016, and the elimination of intersegment revenue net of purchased power and fuel expense.

(c) Exelon corrected an error in the September 30, 2015 balances within Intersegment RNF and RNF from external customers for an understatement of $22 million of Intersegment RNF for Reportable Segments for the nine months ended September 30, 2015, an understatement of RNF from external customers for Reportable Segments of $6 million for the nine months ended September 30, 2015, an overstatement of $22 million of Intersegment RNF for Other for the nine months ended September 30, 2015, and an overstatement of RNF from external customers for Other of $6 million for the nine months ended September 30, 2015. This also included an understatement of total RNF for Reportable Segments and an overstatement of total RNF for Other of $28 million for the nine months ended September 30, 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[(b)]	Intersegment Eliminations	PHI
Operating revenues[(a)]:						
March 24, 2016 to September 30, 2016 Successor						
Rate-regulated electric revenues	$ 1,184	$ 593	$ 714	$ 3	$ (9)	$ 2,485
Rate-regulated natural gas revenues		46				46
Shared service and other revenues				34		34
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						
Nine months ended September 30, 2015 Predecessor						
Rate-regulated electric revenues	$ 1,641	$ 875	$ 1,003	$ 161	$	$ 3,680
Rate-regulated natural gas revenues		129				129
Shared service and other revenues						
Intersegment revenues:						
March 24, 2016 to September 30, 2016 Successor	$ 2	$ 4	$ 2	$ 35	$ (9)	$ 34
January 1, 2016 to March 23, 2016 Predecessor	1	2	1		(4)	
Nine months ended September 30, 2015 Predecessor	4	4	2		(10)	
Net income (loss):						
March 24, 2016 to September 30, 2016 Successor	$ (12)	$ (42)	$ (55)	$ (16)	$ 34	$ (91)
January 1, 2016 to March 23, 2016 Predecessor	32	26	5	(44)		19
Nine months ended September 30, 2015 Predecessor	128	55	37	(23)		197

(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 nine months ended September 30, 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.

Table of Contents

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.

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, 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 tables set forth the consolidated financial results of Exelon for the three and nine months ended September 30, 2016 compared to the same periods in 2015. The 2016 financial results only include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through September 30, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended September 30, 2016							2015	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI[b]	Other	Exelon	Exelon	Variance
Operating revenues	$ 5,035	$ 1,497	$ 788	$ 812	$ 1,394	$ (524)	$ 9,002	$ 7,401	$ 1,601
Purchased power and fuel	2,589	454	272	360	583	(504)	3,754	3,291	(463)
Revenue net of purchased power and fuel[a]	2,446	1,043	516	452	811	(20)	5,248	4,110	1,138
Other operating expenses									
Operating and maintenance	1,336	377	199	178	226	22	2,338	1,996	(342)
Depreciation and amortization	632	196	67	101	182	17	1,195	606	(589)
Taxes other than income	136	82	46	58	124	3	449	310	(139)
Total other operating expenses	2,104	655	312	337	532	42	3,982	2,912	(1,070)
Gain on sales of assets		1					1	2	(1)
Operating income (loss)	342	389	204	115	279	(62)	1,267	1,200	67
Other income and (deductions)									
Interest expense, net	(77)	(197)	(30)	(28)	(64)	(120)	(516)	(253)	(263)
Other, net	185	(80)	2	5	19	(11)	120	(244)	364
Total other income and (deductions)	108	(277)	(28)	(23)	(45)	(131)	(396)	(497)	101
Income (loss) before income taxes	450	112	176	92	234	(193)	871	703	168
Income taxes	173	75	54	36	68	(66)	340	115	(225)
Equity in (losses) earnings of unconsolidated affiliates	(6)					1	(5)	(1)	(4)
Net income (loss)	271	37	122	56	166	(126)	526	587	(61)
Net income (loss) attributable to noncontrolling interests and preference stock dividends	35			2		(1)	36	(42)	(78)
Net income (loss) attributable to common shareholders	$ 236	$ 37	$ 122	$ 54	$ 166	$ (125)	$ 490	$ 629	$ (139)

(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) As a result of the PHI Merger, PHI includes the consolidated results of PHI, Pepco, DPL and ACE from July 1, 2016 through September 30, 2016.

Table of Contents

	Nine Months Ended September 30, 2016							2015	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	PHI[b]	Other	Exelon	Exelon	Variance
Operating revenues	$ 13,363	$ 4,031	$ 2,293	$ 2,421	$ 2,565	$ (1,187)	$ 23,486	$ 22,746	$ 740
Purchased power and fuel	6,609	1,141	809	994	1,037	(1,128)	9,462	10,210	748
Revenue net of purchased power and fuel[a]	6,754	2,890	1,484	1,427	1,528	(59)	14,024	12,536	1,488
Other operating expenses									
Operating and maintenance	4,333	1,113	604	588	921	118	7,677	6,119	(1,558)
Depreciation and amortization	1,329	574	201	307	355	55	2,821	1,818	(1,003)
Taxes other than income	380	222	126	172	248	20	1,168	908	(260)
Total other operating expenses	6,042	1,909	931	1,067	1,524	193	11,666	8,845	(2,821)
Gain on sales of assets	31	6				4	41	10	31
Operating income (loss)	743	987	553	360	4	(248)	2,399	3,701	(1,302)
Other income and (deductions)									
Interest expense, net	(273)	(374)	(92)	(76)	(135)	(229)	(1,179)	(755)	(424)
Other, net	395	(72)	6	16	31	1	377	(179)	556
Total other income and (deductions)	122	(446)	(86)	(60)	(104)	(228)	(802)	(934)	132
Income (loss) before income taxes	865	541	467	300	(100)	(476)	1,597	2,767	(1,170)
Income taxes	293	244	121	109	(9)	(133)	625	805	180
Equity in losses of unconsolidated affiliates	(16)						(16)	(3)	(13)
Net income (loss)	556	297	346	191	(91)	(343)	956	1,959	(1,003)
Net income attributable to noncontrolling interests and preference stock dividends	18			8			26		(26)
Net income (loss) attributable to common shareholders	$ 538	$ 297	$ 346	$ 183	$ (91)	$ (343)	$ 930	$ 1,959	$ (1,029)

(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) As a result of the PHI Merger, PHI includes the consolidated results of PHI, Pepco, DPL and ACE from March 24, 2016 through September 30, 2016.

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Exelon s net income attributable to common shareholders was $490 million for the three months ended September 30, 2016 as compared to $629 million for the three months ended September 30, 2015, and diluted earnings per average common share were $0.53 for the three months ended September 30, 2016 as compared to $0.69 for the three months ended September 30, 2015.

Table of Contents

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1.1 billion for the three months ended September 30, 2016 as compared to the same period in 2015. The quarter-over-quarter increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase of $227 million at Generation due to mark-to-market gains of $88 million in 2016 from economic hedging activities as compared to losses of $139 million in 2015;
- Increase of $57 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from favorable weather and increased capital investment, partially offset by lower allowed electric distribution ROE due to a decrease in treasury rates, as well as, favorable weather;
- Increase of $54 million at PECO primarily due to increased electric distribution revenue pursuant to a rate increase effective January 1, 2016, as well as favorable summer weather;
- Increase of $38 million at BGE primarily due to increased transmission revenue as a result of increased capital investments and operating and maintenance expense recoveries and increased distribution revenue pursuant to a rate increase effective in June 2016; and
- Increase of $811 million in revenue net of purchased power and fuel due to the inclusion of PHI s results for the period of July 1, 2016 to September 30, 2016.

The quarter-over-quarter increase in operating revenue net of purchased power and fuel expense was partially offset by a decrease of $58 million at Generation due to decreased capacity prices and lower realized energy prices in the Mid-Atlantic region.

Operating and maintenance expense increased by $342 million for the three months ended September 30, 2016 as compared to the same period in 2015 primarily due to the following unfavorable factors:

- Increase in Generation s labor, contracting and materials cost of $106 million related to the inclusion of Pepco Energy Services results in 2016;
- Increase of $7 million at BGE primarily due to increased conduit rental fees assessed by the City of Baltimore; and
- Increase of $226 million in operating and maintenance expense due to the inclusion of PHI s results for the period of July 1, 2016 to September 30, 2016.

The quarter-over-quarter increase in operating and maintenance expense was partially offset by a decrease of $20 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 $589 million primarily as a result of accelerated depreciation and amortization expense related to Generation s 2016 decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization at Generation, increased depreciation expense due to ongoing capital expenditures across all operating companies, and the inclusion of PHI s results for the period of July 1, 2016 to September 30, 2016.

Taxes other than income increased by $139 million primarily due to increased property and utility taxes as a result of the inclusion of PHI s results for the period of July 1, 2016 to September 30, 2016.

Interest expense, net increased by $263 million primarily due to the recognition of the interest due on the asserted penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position, the inclusion of PHI s results for the period of July 1, 2016 to September 30, 2016 and higher outstanding debt to fund the PHI acquisition and general corporate purposes.

Other, net increased by $364 million primarily due to the recognition of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position and the change in realized and unrealized gains and losses on NDT funds at Generation.

Exelon s effective income tax rates for the three months ended September 30, 2016 and 2015 were 39.0% and 16.4%, 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.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Exelon s net income attributable to common shareholders was $930 million for the nine months ended September 30, 2016 as compared to $1,959 million for the nine months ended September 30, 2015, and diluted earnings per average common share were $1.00 for the nine months ended September 30, 2016 as compared to $2.22 for the nine months ended September 30, 2015.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1.5 billion for the nine months ended September 30, 2016 as compared to the same period in 2015. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

- Increase of $172 million at ComEd primarily due to increased distribution and transmission formula rate revenue resulting from increased capital investment, as well as, favorable weather;

- Increase of $76 million at BGE primarily due to increased transmission revenue as a result of increased capital investments and operating and maintenance expense recoveries and increased distribution revenue pursuant to a rate increase effective in June 2016;

- Increase of $51 million at PECO primarily due to increased electric distribution revenue pursuant to a rate increase effective January 1, 2016;

- Increase of $20 million at Generation primarily due to approval of the Ginna Reliability Support Services Agreement, decreased nuclear fuel prices and decreased nuclear outage days at higher capacity units, partially offset by lower realized energy prices, and higher oil inventory write downs; and

- Increase of $1,528 million in revenue net of purchased power and fuel due to the inclusion of PHI s results for the period of March 24, 2016 to September 30, 2016.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by a decrease of $371 million at Generation due to mark-to-market losses of $113 million in 2016 from economic hedging activities as compared to gains of $258 million in 2015.

Operating and maintenance expense increased by $1.6 billion for the nine months ended September 30, 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 $513 million of costs;

- Long-lived asset impairments of Upstream assets and certain wind projects at Generation of $171 million;

Increase of $146 million at Generation for the recognition of one-time charges associated with Generation s 2016 decision to early retire the Clinton and Quad Cities nuclear generating facilities;

Increase in Generation s labor, contracting and materials cost of $144 million related to the inclusion of Pepco Energy Services results in 2016;

Increase of $52 million at BGE as a result of one-time charges associated with the reduction of certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the smart grid rate case orders issued by the MDPSC in June and July 2016;

Increase of $22 million at BGE due to increased conduit rental fees assessed by the City of Baltimore;

Table of Contents

Increased storm costs at BGE of $19 million; and

Increase of $607 million, exclusive of merger commitment costs discussed above, due to the inclusion of PHI s results for the period March 24, 2016 to September 30, 2016.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factors:

Decrease of $60 million in pension and non-pension post-retirement benefits resulting from the favorable impact of higher pension and OPEB discount rates in 2016;

Decrease of $31 million in the provision for uncollectible accounts at ComEd, PECO and BGE; and

Decrease of $9 million at PECO due to lower incremental storm costs in the second quarter of 2016 compared to the second quarter of 2015, as a result of the June 2015 storm.

Depreciation and amortization expense increased by $1,003 million primarily as a result of accelerated depreciation and amortization expense related to Generation s 2016 decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization at Generation, increased depreciation expense due to ongoing capital expenditures across all operating companies, and the inclusion of PHI s results for the period of March 24, 2016 to September 30, 2016.

Taxes other than income increased by $260 million primarily due to increased property and utility taxes as a result of the inclusion of PHI s results for the period March 24, 2016 to September 30, 2016.

Gain on sales of assets increased by $31 million primarily as a result of the gain associated with Generation s sale of the retired New Boston generating site.

Interest expense, net increased by $424 million primarily due to the recognition of the interest due on the asserted penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position, higher outstanding debt to fund the PHI acquisition and general corporate purposes and the absence of the forward-starting interest rate swaps in 2016.

Other, net increased by $556 million primarily due to the recognition of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position, the change in realized and unrealized gains and losses on NDT funds at Generation 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 nine months ended September 30, 2016 and 2015 were 39.1% and 29.1%, 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. As a result of the merger, Exelon recorded an after-tax charge of $91 million during the nine months ended September 30, 2016 as a result of the 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 and nine months ended September 30, 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.

Non-GAAP Financial Measures

Exelon s adjusted (non-GAAP) operating earnings for the three months ended September 30, 2016 were $841 million, or $0.91 per diluted share, compared with adjusted (non-GAAP) operating earnings of $757 million, or $0.83 per diluted share for the same period in 2015. Exelon s adjusted (non-GAAP) operating

Table of Contents

earnings for the nine months ended September 30, 2016 were $2,078 million, or $2.24 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,880 million, or $2.13 per diluted share for the same period in 2015. In addition to net income as determined under generally accepted accounting principles in the United States (GAAP), Exelon evaluates its operating performance using adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor s overall understanding of period over period operating results and provide an indication of Exelon s baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies presentations. The Company has provided non-GAAP financial measures as supplemental information and in addition to the financial measures that are calculated and presented in accordance with GAAP. Non-GAAP financial measures should not be deemed more useful than, a substitute for, or an alternative to the most comparable GAAP measures 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 and nine months ended September 30, 2016 as compared to the same periods in 2015. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended September 30,			
	2016		2015	
(All amounts after tax)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	$ 490	$ 0.53	$ 629	$ 0.69
Mark-to-Market Impact of Economic Hedging Activities[(a)]	(54)	(0.06)	85	0.09
Unrealized (Gains) Losses Related to NDT Fund Investments[(b)]	(70)	(0.07)	133	0.15
Merger and Integration Costs[(c)]	13	0.01	12	0.02
Merger Commitments[(d)]	5	0.01		
Long-Lived Asset Impairments[(e)]	11	0.01		
Amortization of Commodity Contract Intangibles[(f)]	13	0.01	2	
Plant Retirements and Divestitures[(g)]	204	0.22		
Cost Management Program[(h)]	7	0.01		
Like-Kind Exchange Tax Position[(i)]	199	0.21		
Asset Retirement Obligation[(j)]			(6)	(0.01)
Tax Settlements[(k)]			(52)	(0.06)
CENG Non-Controlling Interests[(n)]	23	0.03	(46)	(0.05)
Adjusted (non-GAAP) Operating Earnings	$ 841	$ 0.91	$ 757	$ 0.83

Table of Contents

	Nine Months Ended September 30, 2016		2015	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$ 930	$ 1.00	$ 1,959	$ 2.22
Mark-to-Market Impact of Economic Hedging Activities[(a)]	67	0.07	(158)	(0.18)
Unrealized (Gains) Losses Related to NDT Fund Investments[(b)]	(127)	(0.13)	164	0.19
Merger and Integration Costs[(c)]	92	0.10	50	0.06
Merger Commitments[(d)]	400	0.43		
Long-Lived Asset Impairments[(e)]	104	0.11	15	0.02
Amortization of Commodity Contract Intangibles[(f)]	8	0.01	(13)	(0.01)
Plant Retirements and Divestitures[(g)]	338	0.37		
Cost Management Program[(h)]	26	0.03		
Like-Kind Exchange Tax Position[(i)]	199	0.21		
Asset Retirement Obligation[(j)]			(6)	(0.01)
Tax Settlements[(k)]			(52)	(0.06)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps[(l)]			(21)	(0.03)
Midwest Generation Bankruptcy Recoveries[(m)]			(6)	(0.01)
CENG Non-Controlling Interests[(n)]	41	0.04	(52)	(0.06)
Adjusted (non-GAAP) Operating Earnings	$ 2,078	$ 2.24	$ 1,880	$ 2.13

(a) Reflects the impact of net (gains) losses for the three months ended September 30, 2016 and 2015 (net of taxes $35 million and $54 million, respectively) and the nine months ended September 30, 2016 and 2015 (net of taxes of $46 million and $101 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) losses for the three months ended September 30, 2016 and 2015 (net of taxes $75 million and $148 million, respectively) and the nine months ended September 30, 2016 and 2015 (net of taxes of $140 million and $193 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 September 30, 2016 and 2015 (net of taxes $9 million and $9 million, respectively) and the nine months ended September 30, 2016 and 2015 (net of taxes of $35 million and $32 million, respectively), including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, 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 and adjustments incurred as part of the settlement orders approving the PHI acquisition for the three and nine months ended September 30, 2016 (net of taxes of $1 million and $113 million, respectively). See Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail related to PHI Merger commitments.

(e) Reflects the impairment of Upstream assets and certain wind projects at Generation for the three and nine months ended September 30, 2016 (net of taxes of $5 million and $67 million, respectively). Reflects the impairment of investment in long-term leases at Corporate for the nine months ended September 30, 2015 (net of taxes of $9 million).

(f) Reflects the non-cash impact for the three months ended September 30, 2016 and 2015 (net of taxes $8 million and $2 million, respectively) and the nine months ended September 30, 2016 and 2015 (net of taxes of $6 million and $7 million, respectively), of the amortization of intangible assets, net, related to commodity contracts recorded at fair value for the Integrys acquisition in 2015 and Integrys and ConEdison Solutions in 2016.

(g) Reflects the accelerated depreciation and amortization expense, increases to materials and supplies inventory reserves, severance benefits and construction work in progress impairment charges associated with the announced early retirement of Generation s Clinton and Quad Cities nuclear facilities in the second quarter of 2016, partially offset by a gain associated with Generation s sale of the retired New Boston generating site for the three and nine months ended September 30, 2016 (collectively net of taxes $129 million and $214 million, respectively).

(h) Reflects the 2016 severance expense and reorganization costs related to a cost management program for the three and nine months ended September 30, 2016 (net of taxes of $5 million and $17 million, respectively).
(i) Reflects the recognition of a penalty and associated interest expense in the third quarter of 2016, as a result of a tax court decision on Exelon s like-kind exchange tax position for the three and nine months ended September 30, 2016 (net of taxes of $61 million).
(j) Reflects the impact of a non-cash benefit pursuant to the annual update of Generation s decommissioning obligation for the three and nine months ended September 30, 2015 (net of taxes $4 million).
(k) Reflects a benefit related to the favorable settlement of certain income tax positions on Constellation s pre-acquisition tax returns for the three and nine months ended September 30, 2015 (net of taxes $41 million).
(l) Reflects the impact of net losses on forward-starting interest rate swaps at Exelon Corporate related to financing of the PHI acquisition for the nine months ended September 30, 2015 (net of taxes of $14 million).
(m) Reflects a benefit related to the favorable settlement of a long term railcar lease agreement pursuant to the Midwest Generation bankruptcy for the nine months ended September 30, 2015, (net of taxes of $4 million).
(n) Represents Generation s noncontrolling interests 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 retained the Exelon name and is headquartered in Chicago.

As a result of the PHI Merger, Exelon has incurred costs associated with evaluating, structuring and executing the PHI Merger transaction itself, and will continue to incur cost associated with 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 for the PHI Merger included in the Registrant s respective Consolidated Statements of Operations and Comprehensive Income.

	Nine Months Ended September 30, 2016					*Successor* March 24, 2016 to September 30, 2016
	Exelon	**Generation**	**Pepco**	**DPL**	**ACE**	**PHI**
Merger commitments	$ 513	$ 3	$ 126	$ 77	$ 111	$ 314
Changes in accounting and tax related policies and estimates			25	15	5	
Total	$ 513	$ 3	$ 151	$ 92	$ 116	$ 314

In addition to the one-time PHI Merger charges discussed above, for the three and nine months ended September 30, 2016 and 2015, expense has been recognized for the PHI Merger, Constellation acquisition and FitzPatrick acquisition as follows:

	Pre-tax Expense Three Months Ended September 30, 2016								
Merger, Integration and Acquisition Costs:	**Exelon[(a)]**	**Generation[(a)]**	**ComEd**	**PECO**	**BGE**	**PHI[(a)]**	**Pepco[(a)]**	**DPL[(a)]**	**ACE[(a)]**
Transaction[(c)]	$ 1	$	$	$	$	$	$	$	$
Employee-Related[(d)]	1					1			
Other	21	11		2	2	7	3	2	2
Total	$ 23	$ 11	$	$ 2	$ 2	$ 8	$ 3	$ 2	$ 2

Table of Contents

Merger, Integration and Acquisition Costs:	Exelon	Pre-tax Expense Three Months Ended September 30, 2015 Generation	ComEd	PECO	BGE
Transaction[c]	$ 5	$	$	$	$
Other	17	10	3	1	2
Total	$ 22	$ 10	$ 3	$ 1	$ 2

Merger, Integration and Acquisition Costs:	Exelon[a]	Generation[a]	ComEd	PECO	BGE	PHI[a]	Pepco[a]	DPL[a]	ACE[a]
	Pre-tax Expense Nine Months Ended September 30, 2016								
Transaction[c]	$ 36	$	$	$	$	$	$	$	$
Employee-Related[d]	74	10	1	1	1	61	29	17	14
Other[e]	16	21	(8)	3	(3)	2	(3)	1	3
Total	$ 126	$ 31	$ (7)	$ 4	$ (2)	$ 63	$ 26	$ 18	$ 17

Merger and Integration Costs:	Exelon	Pre-tax Expense Nine Months Ended September 30, 2015 Generation	ComEd	PECO	BGE
Financing[b]	$ 21	$	$	$	$
Transaction[c]	14				
Other	49	30	9	4	4
Total	$ 84	$ 30	$ 9	$ 4	$ 4

(a) For Exelon, Generation, PHI, Pepco, DPL, and ACE, includes the operations of the acquired businesses beginning on March 24, 2016.
(b) Reflects costs incurred at Exelon related to the financing of the PHI Merger, including upfront credit facility fees and mark-to-market activity on forward-starting interest rate swaps.
(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) For the nine months ended September 30, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $10 million, $3 million and $13 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, that have been deferred and recorded as a regulatory asset for anticipated recovery. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information.

As of September 30, 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 September 30, 2016, Exelon and PHI have incurred approximately $560 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.

Table of Contents

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 steadily growing earnings, which translates to a stable currency in our stock.

Generation s competitive businesses provide free cash flow to support investment in Exelon s utilities and long-term, contracted assets at Generation, and debt reduction.

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 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 energy 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.

Several nuclear units within the Exelon fleet and nationally are economically challenged, threatened by persistently low prices and out-of-market payments to select generation sources. Some units have already retired prematurely for economic reasons, and Exelon has announced the planned early shutdown of its Clinton and Quad Cities units. Other Exelon units face similar challenges, most notably Ginna, Nine Mile Point and TMI. In August 2016, the New York Public Service Commission issued an order adopting the Clean Energy Standard (CES), designed to provide payments under a Zero Emissions Credit program to Generation s Ginna and Nine Mile Point and Entergy s James A. FitzPatrick nuclear plants in recognition of the environmental benefits of their zero emissions attributes. Exelon is working to develop other potential solutions at the state, federal and RTO levels so that markets and/or the states more appropriately value the carbon-free emission attribute of nuclear generation.

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.

Table of Contents

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 approximately $350 million and $50 million, respectively, of which approximately 35% of run-rate savings are expected to be achieved by the end of 2016 and fully realized in 2018. At least 75% of the savings are expected to be allocated to Generation, with the remaining amount allocated to the Utility Registrants. Exelon anticipates the earnings per share savings impact on EPS will be within $0.13 to $0.18 from 2018 forward.

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

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

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

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

In 2016, as a result of the plant retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges in Operating and maintenance expense of $146 million related to materials and supplies inventory reserve adjustments, employee-related costs and construction work-in-progress (CWIP) impairments, among other items. In addition to these one-time charges, there will be ongoing annual incremental non-cash charges to earnings stemming from shortening the expected economic useful life of Clinton and Quad Cities primarily related to accelerated depreciation of plant assets (including any asset retirement costs (ARC)), accelerated amortization of nuclear fuel, and additional asset retirement obligation (ARO) accretion expense associated with the changes in decommissioning timing and cost assumptions. Exelon s and Generation s third quarter 2016 results include an incremental $443 million of pre-tax expense for these items. The following table summarizes the estimated annual amount and timing of such expected incremental non-cash expense items through 2018.

Income statement expense (pre-tax)	September 30, 2016	2016	Projected[a] 2017	2018
Depreciation and Amortization				
Accelerated depreciation[b]	$ 459	$ 800	$ 860	$ 200
Accelerated nuclear fuel amortization	37	70	75	20
Operating and Maintenance				
Increase ARO accretion, net of contractual offset[c]	2	5	5	5
Contractual offset for ARC depreciation[c]	(55)	(100)	(160)	(60)
Total	$ 443	$ 775	$ 780	$ 165

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.
(b) Reflects incremental accelerated depreciation of plant assets, including any ARC.
(c) For Quad Cities based on the regulatory agreement with the Illinois Commerce Commission, decommissioning-related activities are offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

Please refer to Note 12 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail on changes to the Nuclear decommissioning ARO balances resulting from the early retirement of Clinton and Quad Cities.

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

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

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

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

Assuming the successful implementation of the CES and its continued effectiveness, Generation and CENG would no longer consider Ginna and Nine Mile Point to be at heightened risk of early retirement; however, absent the CES for the full expected duration they will remain at heightened risk. The precise timing of an early retirement date for any of these plants, and the resulting financial statement impacts, may be affected by a number of factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations, where applicable, and just prior to its next scheduled nuclear refueling outage.

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant s owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 12 Nuclear Decommissioning to the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

It is currently estimated that Clinton will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. Quad Cities is also at risk for such a shortfall. A shortfall could require Exelon to post parental guarantees for Generation s share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward. Within two years of shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. Considering the three alternative decommissioning approaches available for each site, the most costly estimates currently anticipated could require parental guarantees of up to $375 million for Clinton in order to access its NDT fund for radiological decommissioning costs. Although Quad Cities is better positioned than Clinton to avoid the need for a parental guarantee, a guarantee of up to $110 million, at Generation s ownership percentage, may be required in order for the site to access its NDT fund for radiological decommissioning costs. As of September 30, 2016, the additional plants at the highest risk of early retirement, Ginna, Nine Mile Point and TMI, pass the NRC minimum funding test based on their current license lives. However, in the event of an early retirement the most costly estimates currently anticipated could require parental guarantees of up to $115 million, $200 million, and $65 million for Ginna, Nine Mile Point and TMI, respectively, at Generation s ownership percentages.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant s owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). 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 and others holding ownership interests. While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the United States Department of Energy reimbursement agreements or future litigation, across the three alternative decommissioning approaches available, for the next 10 years, Clinton could incur spent fuel management and site restoration costs of up to $160 million, net of taxes. Quad Cities is better positioned to pass the test than Clinton. 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 over the next ten years of up to $185 million, net of taxes, at Generation s ownership percentage. If an early retirement decision is made and Ginna, Nine Mile Point, or TMI were to fail the exemption test, each could incur spent fuel management and site restoration costs over the next ten years of up to $60 million, $140 million and $145 million, net of taxes, respectively, at Generation s ownership percentages.

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

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

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

Table of Contents

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

As of September 30, 2016, Generation has paid a non-refundable deposit of $10 million and reimbursed Entergy for $9 million in costs all of which have been classified with Other noncurrent assets on Exelon s and Generation s Consolidated Balance Sheets for a total amount of $19 million. These amounts are also reflected within Acquisition of businesses on Exelon s and Generation s Consolidated Statements of Cash Flows.

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 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), its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015), its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015), and its 2019/2020 Base Residual Auction in May 2016. In June 2016, several parties appealed the FERC s decision approving PJM s market changes to the Court of Appeals for the D. C. Circuit. Exelon has intervened in the matter in support of FERC s decision. The outcome of this appeal is unclear at this time, but could impact earnings.

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

Table of Contents

Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints alleged 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 in April 2016 that set capacity prices beginning June 1, 2016. In response to this order, MISO filed conforming rule changes with the FERC. 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 prejudge 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 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement. On September 8, 2016, a coalition of MISO transmission customers filed a complaint alleging that the MISO failed to follow its tariff in conducting the capacity auction and, as a result, overstated the clearing prices including in zone 4 where the transmission customers allege that the rate should have been $20 per MW per day. Among other things, the transmission customers seek refunds of the alleged excess payment. It is too early in this proceeding to predict its outcome. Nonetheless, it could detrimentally impact the auction results for Clinton.

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 is engaging 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 inappropriately subsidize new generation development and existing generation which may result in artificially depressed wholesale energy and capacity prices.

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 to the Combined Notes to Consolidated Financial Statements 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 inappropriate state efforts, if successful and unabated in future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar 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 sought ratepayer guaranteed subsidies via the proposed Riders. While AEP and FE initially filed for approval of 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. On March 31, 2016, PUCO issued separate orders generally approving each of the FE and AEP arrangements. In addition, separate complaints were 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. As a result, we do not believe that the PPAs impacted the results of PJM s recently completed capacity auctions. Nonetheless, further action by AEP and FE related to the PPAs is possible. Indeed, FE recently filed a restructured arrangement at PUCO that appears to achieve a similar result without relying on a PPA. 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 continues to monitor developments in Ohio, Maryland, New Jersey, New England and other states 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 Pepco, a decrease in projected load for electricity for BGE, DPL and ACE, and an essentially flat projected load for electricity for ComEd and PECO. ComEd, PECO,BGE, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by 0.4%, 0.0%, (1.4)%, 1.0%, (1.7)% and (1.6)%, respectively, in 2016 compared to 2015.

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.

Table of Contents

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. The second quarter 2016 dividend was paid 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.

Exelon s Board of Directors declared the third quarter 2016 dividends of $0.318 per share each on Exelon s common stock. The third quarter 2016 dividend was paid on September 9, 2016.

Exelon s Board of Directors declared the fourth quarter 2016 dividends of $0.318 per share each on Exelon s common stock. The fourth quarter 2016 dividend is payable on December 9, 2016.

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 September 30, 2016, the percentage of expected generation hedged for the major reportable segments is 98%-101%, 85%-88% and 54%-57% for 2016, 2017 and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, 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 57% 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.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Table of Contents

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 $9 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 September 30, 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 $9.0 billion. Generation also has bilateral credit facilities with aggregate maximum availability of $525 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 September 30, 2016, approximately 23%, or $2.2 billion, of the Registrants aggregate total commitments were with European banks. The credit facilities include $9.5 billion in aggregate total commitments of which $7.9 billion was available as of September 30, 2016, due to outstanding letters of credit. There was $40 million of borrowings under the Registrants bilateral credit facilities as of September 30, 2016. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities for additional information.

Table of Contents

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 are expected to 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, SO2 and NOx. 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 economy with the urgent need to reduce national GHG emissions. In the absence of federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change (UNFCCC or Convention). On October 5, 2016, the Paris Climate Change Agreement entered into effect, and the next meeting of the Conference of the Parties in November 2016 will address procedural issues as countries take action to meet their voluntary carbon emission reductions. See ITEM 1. BUSINESS, Global Climate Change of the Exelon 2015 Form 10-K for further discussion.

Table of Contents

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, Salem and Wolf Hollow. 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

NRC Task Force Insights from the Fukushima Daiichi Accident (Exelon and Generation). In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force s report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2016 through 2019 is expected to be between approximately $150 million and $175 million of capital (which includes approximately $25 million for the CENG plants) and $25 million of operating expense (which includes approximately $5 million for the CENG plants). These revised amounts take into consideration the effect of the early plant retirements of Clinton and Quad Cities (see Note 7 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information). Generation s current assessments are specific to the Tier 1 recommendations as the NRC has not finalized actions with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input.

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the the New York Public Service Commission (NYPSC) issued an order establishing the Clean Energy Standard (CES), a component of which includes creation of a Tier 3 Zero Emission Credit (ZEC) program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined by the federal government. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills. The CES initially identifies the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. The program specifically provides that Nine Mile Point Units 1 & 2 qualify jointly as a single facility and if either unit permanently ceases operations then both units will no longer qualify for ZEC payments for the remainder of the program. As issued, the order provides that the duration of the program beyond the first tranche is conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018; however, Generation and CENG requested clarification, or in the alternative limited rehearing, that this condition is applicable to the FitzPatrick facility only and has no bearing on the 12-year duration of the program for Ginna or Nine Mile Point. To date, several parties have filed with the NYPSC requests for rehearing or reconsideration of the CES and on October 19, 2016 a coalition of fossil generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically that the ZEC program interferes with FERC s jurisdiction over wholesale rates and that it discriminates against out of state competitors. Generation and CENG will seek to intervene in the case and to dismiss the lawsuit. Other legal challenges remain possible and the outcomes of each of these challenges is currently uncertain. Negotiations with NYSERDA regarding contracts for the sale of ZECs from Ginna, Nine Mile Point and FitzPatrick are ongoing, and Generation expects that NYSERDA will enter into final agreements during the fourth quarter of 2016. See Note 7 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information relative to Ginna and Nine Mile Point and Note 4 Mergers, Acquisitions and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information on Generation s proposed acquisition of FitzPatrick.

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.

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

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

2016 Electric and Natural Gas Distribution Base Rates (Exelon, PHI and DPL). On May 17, 2016, DPL filed an application with the DPSC to increase its annual electric and natural gas distribution base rates by $63 million and $22 million, respectively, based on a requested ROE of 10.6%. While the DPSC is not required to issue a decision on the application within a specified period of time, Delaware law allows DPL to put into effect $2.5 million of the rate increase two months after filing the applications which were effective July 16, 2016. It also allows the entire requested rate increase seven months after filing, subject to a cap and a refund obligation based on the final DPSC order. DPL cannot predict how much of the requested increase the DPSC will approve.

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

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

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

On August 26, 2016, BGE filed an appeal of the MDPSC s orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC s order but with the Circuit Court for Baltimore City. Refer to the Conduit Lease with City of Baltimore disclosure below for further details about BGE s efforts 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. Refer to Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on the impact of the ultimate disallowances contained in the orders to BGE.

2016 Electric Distribution Base Rates (Exelon, PHI and Pepco). On June 30, 2016, Pepco filed an application with the DCPSC to increase its annual electric distribution base rates by $86 million, which was updated to $82 million on October 14, 2016, based on a requested ROE of 10.6%. The DCPSC has issued a procedural schedule indicating a final decision will be issued by July 25, 2017. Any adjustments to its rates approved by the DCPSC are expected to take effect soon thereafter. Pepco cannot predict how much of the requested increase the DCPSC will approve.

On April 18, 2016, a party to a separate DCPSC proceeding filed a motion to suspend Pepco s bill stabilization adjustment (BSA), which decouples distribution revenues from utility customers from the amount of electricity delivered. On September 9, 2016, the DCPSC denied the party s motion and determined that the appropriate forum in which to determine whether the BSA continues to be just and reasonable is in Pepco s rate case proceeding. In addition, the DCPSC stated that it was putting Pepco on notice that all funds collected for the BSA from January 2015 to the issuance of a decision in the rate case proceeding are subject to refund should the

DCPSC determine that such funds were not justly or reasonably collected. On October 7, 2016, Pepco filed for reconsideration of this order and requested clarification that the order was not final and that the BSA matter would be decided in the base rate case. Pepco also argued that, if the order were considered final, the DCPSC reconsider its ruling that funds collected from the BSA can be retroactively refunded. Pepco cannot predict the outcome of this matter or the impact of a refund if ordered by the DCPSC.

2016 Electric Distribution Base Rates (Exelon, PHI and ACE). On August 24, 2016, the NJBPU issued an order approving a stipulation of settlement among ACE, the New Jersey Division of Rate Counsel, NJBPU Staff and Unimin Corporation, and an increase of $45 million (before New Jersey sales and use tax) to its electric distribution base rates, with the new rates effective immediately. The stipulation of settlement provided that a determination on PowerAhead would be separated into a phase II of the rate proceeding and decided at a later date and the parties would seek to resolve the matter by the end of 2016, although resolution will most likely occur in the first quarter of 2017. PowerAhead includes capital investments to advance modernization of the electric grid through energy efficiency, increased distributed generation, and resiliency, focused on improving the distribution system s ability to withstand major storm events. ACE cannot predict if the NJBPU will approve the PowerAhead initiative.

Update and Reconciliation of Certain Under-Recovered Balances (Exelon, PHI and ACE). *O*n February 1, 2016, ACE submitted its 2016 annual petition with the NJBPU seeking to reconcile and update (i) charges related to the recovery of above-market costs associated with ACE s long-term power purchase contracts with the NUGs and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE s uncollectible accounts.

The net impact of adjusting the charges as proposed is an overall annual rate increase of $9 million (revised to $19 million in April 2016, based upon an update for actuals through March 2016), including New Jersey sales and use tax. The matter is pending at the NJBPU.

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

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

(a) All rates are effective June 2016.
(b) Refers to the weighted average debt and equity return on transmission rate bases.
(c) As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.

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 underground conduit

Table of Contents

system 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 Court for Baltimore City 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. On July 12-13, 2016, the parties participated in non-binding mediation in an effort to resolve their disputes, but such mediation was unsuccessful. Due to concerns with the scheduling order entered by the Circuit Court, the parties stipulated to the dismissal of the lawsuit; however, BGE has the right to re-file the lawsuit. On August 25, 2016, BGE filed a motion to intervene in a lawsuit filed by several other tenants in the conduit system against the City in the United States District Court for the District of Maryland. BGE cannot predict the outcome of its motion for intervention or the accompanying complaint.

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 proposed to recover the annual increase in conduit fees effective November 1, 2015 of approximately $30 million through a surcharge. On June 3, 2016, the MDPSC issued a final order which did not allow BGE to recover or defer the $30 million in annual Baltimore City conduit fees. On June 30, 2016, BGE filed a petition for rehearing of the June 3 order requesting, among other things, that the MDPSC modify its decision to deny recovery of the Baltimore County conduit fees. On July 29, 2016, the MDPSC issued an order on the petitions for rehearing that, among other things, denied BGE s request that it be allowed to defer or recover through a surcharge the increase in Baltimore City underground conduit fees. On August 26, 2016, BGE filed an appeal of the MDPSC s orders with the Circuit Court for Baltimore County. On August 29, 2016, the residential consumer advocate also filed an appeal of the MDPSC s order but with the Circuit Court for Baltimore City. BGE cannot predict the outcome of these appeals.

Employees

During the second and third quarters of 2016, Exelon BSC and ComEd extended the collective bargaining agreement (CBA) with IBEW Local 15 by three years; with an expiration date of September 30, 2022. Exelon Generation extended its CBA with both the IBEW Local 15 (covering the five (5) Midwest nuclear plants) and IBEW Local 51 (Clinton) by three years; with expiration dates of April 30, 2022 and December 15, 2023, respectively. Additionally, Exelon Nuclear Security successfully ratified its CBA with the UGSOA Local 17 at Oyster Creek to an extension of five (5) years, and Exelon Power successfully ratified its CBA with the IBEW Local 614 to a three (3) extension.

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 September 30, 2016, the Registrants critical accounting policies and estimates had not changed significantly from December 31, 2015.

Table of Contents

Results of Operations

Net Income (Loss) Attributable to Common Shareholders by Registrant

	Three Months Ended September 30,		Favorable (Unfavorable)	Nine Months Ended September 30,		Favorable (Unfavorable)
	2016	2015	Variance	2016[(a)]	2015	Variance
Exelon	$ 490	$ 629	$ (139)	$ 930	$ 1,959	$ (1,029)
Generation	236	377	(141)	538	1,218	(680)
ComEd	37	149	(112)	297	339	(42)
PECO	122	90	32	346	299	47
BGE	54	51	3	183	202	(19)
Pepco	79	60	19	20	128	(108)
DPL	44	15	29	(16)	55	(71)
ACE	47	22	25	(50)	37	(87)

(a) For Pepco, DPL and ACE, reflects that Registrant s operations for the nine months ended September 30, 2016. For Exelon and Generation, includes the operations of the PHI acquired businesses for the period of March 24, 2016 through September 30, 2016.

	Successor	*Predecessor*	*Successor*	*Predecessor*	
	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	March 24 to September 30, 2016	January 1 to March 23, 2016	Nine Months Ended September 30, 2015
PHI	$ 166	$ 91	$ (91)	$ 19	$ 197

224

Table of Contents

Results of Operations Generation

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Favorable (Unfavorable) Variance
Operating revenues	$ 5,035	$ 4,768	$ 267	$ 13,363	$ 14,841	$ (1,478)
Purchased power and fuel expense	2,589	2,519	(70)	6,609	7,800	1,191
Revenue net of purchased power and fuel[(a)]	2,446	2,249	197	6,754	7,041	(287)
Other operating expenses						
Operating and maintenance	1,336	1,241	(95)	4,333	3,860	(473)
Depreciation and amortization	632	264	(368)	1,329	774	(555)
Taxes other than income	136	123	(13)	380	369	(11)
Total other operating expenses	2,104	1,628	(476)	6,042	5,003	(1,039)
Gain on sales of assets		1	(1)	31	7	24
Operating income	342	622	(280)	743	2,045	(1,302)
Other income and (deductions)						
Interest expense, net	(77)	(68)	(9)	(273)	(269)	(4)
Other, net	185	(257)	442	395	(193)	588
Total other income and (deductions)	108	(325)	433	122	(462)	584
Income before income taxes	450	297	153	865	1,583	(718)
Income taxes	173	(36)	(209)	293	371	78
Equity in losses of unconsolidated affiliates	(6)	(1)	(5)	(16)	(4)	(12)
Net income	271	332	(61)	556	1,208	(652)
Net income (loss) attributable to noncontrolling interests	35	(45)	(80)	18	(10)	(28)
Net income attributable to membership interest	$ 236	$ 377	$ (141)	$ 538	$ 1,218	$ (680)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Generation s net income attributable to membership interest for three months ended September 30, 2016 decreased compared to the same period in 2015, primarily due to higher operating and maintenance expense, higher depreciation and amortization expense and increased income tax expense, partially offset by higher revenue, net of purchased power and fuel expense and increased other income. The increase in operating and maintenance expense is primarily related to impairment of Upstream assets and increased costs related to the cost management program. The increase in depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures. The increase in income taxes given a decrease in the domestic production activities

225

deduction and absence of favorable settlement of certain income tax positions at Constellation in 2015. The increase in revenue net of purchased power and fuel expense primarily relates to higher mark-to-market results in 2016 compared to 2015 and the Ginna Reliability Support Services Agreement partially offset by decreased capacity prices and lower realized energy prices. The increase in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Generation s net income attributable to membership interest for the nine months ended September 30, 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, partially offset by increased other income. The decrease in revenue net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015, lower realized energy prices and increased oil inventory write-downs, partially offset by the Ginna Reliability Support Services Agreement, decreased fuel prices and a decrease in outage days at higher capacity units despite an increase in overall outage days. The increase in operating and maintenance expense is primarily related to the decision to early retire the Clinton and Quad Cities nuclear generating facilities, impairment of Upstream assets and certain wind projects and increased costs related to the cost management program. The increase in depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the decision to early retire the Clinton and Quad Cities nuclear generating facilities, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures. The increase in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds.

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.

Table of Contents

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

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

The following business activities are not allocated to a region, and are reported under Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation s overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.

Generation evaluates the operating performance of its 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 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 and nine months ended September 30, 2016 and 2015, Generation s revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2016	2015	Variance	% Change	2016	2015	Variance	% Change
Mid-Atlantic[(a)]	$ 887	$ 997	$ (110)	(11.0)%	$ 2,556	$ 2,677	$ (121)	(4.5)%
Midwest[(b)]	781	756	25	3.3%	2,229	2,205	24	1.1%
New England	160	133	27	20.3%	350	379	(29)	(7.7)%
New York	194	170	24	14.1%	592	502	90	17.9%
ERCOT	93	111	(18)	(16.2)%	231	235	(4)	(1.7)%
Other Power Regions	77	83	(6)	(7.2)%	253	193	60	31.1%
Total electric revenue net of purchased power and fuel expense	2,192	2,250	(58)	(2.6)%	6,211	6,191	20	0.3%
Proprietary Trading	3		3	n.m.	9	3	6	200.0%
Mark-to-market gains / (losses)	88	(139)	227	(163.3)%	(113)	258	(371)	(143.8)%
Other[(c)]	163	138	25	18.1%	647	589	58	9.8%
Total revenue net of purchased power and fuel expense	$ 2,446	$ 2,249	$ 197	8.8%	$ 6,754	$ 7,041	$ (287)	(4.1)%

(a) Results of transactions with PECO and BGE are included in the Mid-Atlantic region. Results of transactions with Pepco, DPL, and ACE are included in the Mid-Atlantic region for the successor period of March 24, 2016 to September 30, 2016.
(b) Results of transactions with ComEd are included in the Midwest region.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $22 million and $4 million decrease to revenue net of purchased power and fuel expense for the three months ended September 30, 2016 and 2015, respectively, and accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed in Note 7 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements of $28 million for the three months ended September 30, 2016. Also includes amortization of intangible assets and liabilities related to

Table of Contents

commodity contracts recorded at fair value of a $15 million decrease and $20 million increase to revenue net of purchased power and fuel expense for the nine months ended September 30, 2016 and 2015, respectively, and accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed in Note 7 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements of $38 million for the nine months ended September 30, 2016.

Generation s supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended September 30, 2016	2015	Variance	% Change	Nine Months Ended September 30, 2016	2015	Variance	% Change
Nuclear generation								
Mid-Atlantic[(a)]	15,604	16,446	(842)	(5.1)%	47,035	47,783	(748)	(1.6)%
Midwest	24,262	23,927	335	1.4%	70,925	69,802	1,123	1.6%
New York[(a)]	4,843	4,807	36	0.7%	14,002	14,057	(55)	(0.4)%
Total Nuclear Generation	44,709	45,180	(471)	(1.0)%	131,962	131,642	320	0.2%
Fossil and Renewables								
Mid-Atlantic	706	719	(13)	(1.8)%	2,290	2,028	262	12.9%
Midwest	273	262	11	4.2%	1,046	1,057	(11)	(1.0)%
New England	1,886	1,840	46	n.m.	5,826	2,575	3,251	n.m.
New York	1	1		%	3	3		%
ERCOT	2,472	2,306	166	7.2%	5,726	4,600	1,126	24.5%
Other Power Regions	2,103	1,945	158	8.1%	6,245	6,014	231	3.8%
Total Fossil and Renewables	7,441	7,073	368	5.2%	21,136	16,277	4,859	29.9%
Purchased Power								
Mid-Atlantic	7,139	3,511	3,628	103.3%	14,024	6,719	7,305	108.7%
Midwest	461	515	(54)	(10.5)%	1,855	1,511	344	22.8%
New England	3,927	5,787	(1,860)	(32.1)%	11,863	17,937	(6,074)	(33.9)%
ERCOT	2,895	2,422	473	19.5%	7,448	7,569	(121)	(1.6)%
Other Power Regions	3,803	5,812	(2,009)	(34.6)%	10,281	14,186	(3,905)	(27.5)%
Total Purchased Power	18,225	18,047	178	1.0%	45,471	47,922	(2,451)	(5.1)%
Total Supply/Sales by Region[(b)]								
Mid-Atlantic[(c)]	23,449	20,676	2,773	13.4%	63,349	56,530	6,819	12.1%
Midwest[(c)]	24,996	24,704	292	1.2%	73,826	72,370	1,456	2.0%
New England	5,813	7,627	(1,814)	(23.8)%	17,689	20,512	(2,823)	(13.8)%
New York	4,844	4,808	36	0.7%	14,005	14,060	(55)	(0.4)%
ERCOT	5,367	4,728	639	13.5%	13,174	12,169	1,005	8.3%
Other Power Regions	5,906	7,757	(1,851)	(23.9)%	16,526	20,199	(3,673)	(18.2)%
Total Supply/Sales by Region	70,375	70,300	75	0.1%	198,569	195,840	2,729	1.4%

(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 1,506 GWh and 1,913 GWh for the three months ended September 30, 2016 and 2015, respectively, and 4,015 GWh and 5,378 GWh for the nine months ended September 30, 2016 and 2015, respectively.

Table of Contents

(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 PHI Merger, includes affiliate sales to Pepco, DPL and ACE in the Mid-Atlantic region for the Successor period of March 24, 2016 to September 30, 2016.

Mid-Atlantic

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $110 million decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects decreased capacity prices, lower realized energy prices and increased nuclear outage days.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $121 million decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic primarily reflects lower realized energy prices, decreased capacity prices and higher oil inventory write-downs in 2016, partially offset by increased load volumes served.

Midwest

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $25 million increase in revenue net of purchased power and fuel expense in the Midwest primarily reflects decreased nuclear outage days and higher realized energy prices.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $24 million increase in revenue net of purchased power and fuel expense in the Midwest primarily reflects decreased nuclear outage days and increased capacity prices, partially offset by lower realized energy prices.

New England

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $27 million increase in revenue net of purchased power and fuel expense in New England was driven by increased capacity prices.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $29 million decrease in revenue net of purchased power and fuel expense in New England was driven by lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by increased capacity prices.

New York

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $24 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the impact of the Ginna Reliability Support Service Agreement.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $90 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the approval of the Ginna Reliability Support Service Agreement, partially offset by lower realized energy prices.

ERCOT

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $18 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $4 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices, partially offset by increased output from renewable assets.

Table of Contents

Other Power Regions

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $6 million decrease in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to lower realized energy prices.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $60 million increase in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Proprietary Trading

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The $3 million increase in revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $6 million increase in revenue net of purchased power and fuel expense in Proprietary Trading was primarily due to congestion activity.

Mark-to-market

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Mark-to-market gains on economic hedging activities were $88 million for the three months ended September 30, 2016 compared to losses of $139 million for the three months ended September 30, 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.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Mark-to-market losses on economic hedging activities were $113 million for the nine months ended September 30, 2016 compared to gains of $258 million for the nine months ended September 30, 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 September 30, 2016 Compared to Three Months Ended September 30, 2015. The $25 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects, partially offset by the amortization of energy contracts recorded at fair value associated with prior acquisitions, and accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed in Note 7 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The $58 million increase in other revenue net of purchased power and fuel was primarily due to revenue related to the inclusion of Pepco Energy Services results in 2016 and revenue related to energy efficiency projects, partially offset by the amortization of energy contracts recorded at fair value associated with prior acquisitions, and accelerated nuclear fuel amortization associated with nuclear decommissioning as discussed in Note 7 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for the three and nine months ended September 30, 2016 as compared to the same periods 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Nuclear fleet capacity factor[(a)]	96.3%	95.5%	94.8%	93.8%

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon.

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The nuclear fleet capacity factor increased primarily due to fewer refueling and non-refueling outage days, excluding Salem outages, during the three months ended September 30, 2016 compared to the same period in 2015. For the three months ended September 30, 2016 and 2015, planned refueling outage days totaled 17 and 27, respectively. During the same periods, non-refueling outage days totaled zero and 11, respectively.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The nuclear fleet capacity factor increased primarily due to fewer refueling and non-refueling outage days, excluding Salem outages, during the nine months ended September 30, 2016 compared to the same period in 2015. For the nine months ended September 30, 2016 and 2015, planned refueling outage days totaled 174 and 187, respectively. During the same periods, non-refueling outage days totaled 31 and 61, respectively.

Operating and Maintenance

The changes in operating and maintenance expense for the three and nine months ended September 30, 2016 as compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Labor, other benefits, contracting, materials	$ 106	$ 144
Nuclear refueling outage costs, including the co-owned Salem plants[(a)]	(8)	10
Corporate allocations[(b)]	24	12
Merger and integration costs	5	5
Merger commitments		3
Plant retirements and divestitures[(c)]	(36)	91
Impairment of long-lived assets[(d)]	15	171
Cost management program[(e)]	11	35
Midwest Generation bankruptcy recoveries[(f)]		10
Asset retirement obligation update[(g)]	10	10
Pension and non-pension postretirement benefits expense[(h)]	(11)	(35)
Accretion expense	(11)	(10)
Other	(10)	27
Increase in operating and maintenance expense	$ 95	$ 473

(a) Primarily reflects the unfavorable impact of the timing and extended duration of an outage at the Salem nuclear power plant for the nine months ended September 30, 2016.
(b) Reflects an increased share of corporate allocated costs.
(c) Represents the decision to early retire the Clinton and Quad Cities nuclear facilities in 2016.
(d) Reflects the impact of 2016 charge to earnings related to the impairment of Upstream assets and certain wind projects.
(e) Represents the 2016 severance expense and reorganization costs related to a cost management program.
(f) Reflects a 2015 benefit for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy.
(g) Reflects the impact of the 2015 annual update of Generation s nuclear decommissioning obligation for Non-Regulatory Agreement Units.
(h) Reflects favorable impact of higher pension and OPEB discount rates in 2016.

Depreciation and Amortization

Depreciation and amortization expense for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015 increased primarily due to accelerated depreciation related to the decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, increased nuclear decommissioning amortization and increased depreciation expense due to ongoing capital expenditures.

Taxes Other Than Income

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Taxes other than income taxes, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. The increase primarily relates to property and gross receipts tax.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Taxes other than income taxes, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. The increase primarily relates to gross receipts and sales and use tax.

Gain on Sales of Assets

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Gain on sales of assets for the three months ended September 30, 2016 compared to the three months ended September 30, 2015 remained relatively stable.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Gain on sales of assets for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 increased as a result of the gain associated with Generation s sale of the New Boston generating site.

Interest Expense, net

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. The increase in interest expense for the three months ended September 30, 2016 compared to the three months ended September 30, 2015 is primarily due to higher outstanding debt.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Interest expense for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 remained relatively stable.

Table of Contents

Other, Net

Other, net for the three and nine months ended September 30, 2016 compared to the three and nine months ended September 30, 2015 increased primarily due to the change in the realized and unrealized gains and losses related to NDT funds of Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $39 million and $(55) million for the three months ended September 30, 2016 and 2015, respectively, and $84 million and $(44) million for the nine months ended September 30, 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 and losses on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and nine months ended September 30, 2016 and 2015:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Net unrealized gains (losses) on decommissioning trust funds	$ 116	$ (218)	$ 216	$ (274)
Net realized gains (losses) on sale of decommissioning trust funds	12	(3)	26	53

Equity in Losses of Unconsolidated Affiliates

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. Equity in losses of unconsolidated affiliates for the three months ended September 30, 2016 compared to the three months ended September 30, 2015 remained relatively stable.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. The increase in equity in losses of unconsolidated affiliates for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015 increased as a result of losses on equity investments.

Effective Income Tax Rate

Generation s effective income tax rate was 38.4% and 33.9% for the three and nine months ended September 30, 2016, respectively, compared to (12.1)% and 23.4% for the same periods during 2015. 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 September 30, 2016	Three Months Ended September 30, 2015	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Favorable (Unfavorable) Variance
Operating revenues	$ 1,497	$ 1,376	$ 121	$ 4,031	$ 3,709	$ 322
Purchased power expense	454	390	(64)	1,141	991	(150)
Revenue net of purchased power expense[a][b]	1,043	986	57	2,890	2,718	172
Other operating expenses						
Operating and maintenance	377	404	27	1,113	1,166	53
Depreciation and amortization	196	176	(20)	574	528	(46)
Taxes other than income	82	79	(3)	222	225	3
Total other operating expenses	655	659	4	1,909	1,919	10
Gain on sales of assets	1		1	6		6
Operating income	389	327	62	987	799	188
Other income and (deductions)						
Interest expense, net	(197)	(83)	(114)	(374)	(248)	(126)
Other, net	(80)	4	(84)	(72)	14	(86)
Total other income and (deductions)	(277)	(79)	(198)	(446)	(234)	(212)
Income before income taxes	112	248	(136)	541	565	(24)
Income taxes	75	99	24	244	226	(18)
Net income	$ 37	$ 149	$ (112)	$ 297	$ 339	$ (42)

(a) ComEd evaluates its operating performance using the measure of Revenue net of purchased power expense. ComEd believes that Revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of Revenue net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) For regulatory recovery mechanisms, including ComEd s electric distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Three Months Ended September 30, 2016 Compared to Three months ended September 30, 2015. ComEd s Net income for the three months ended September 30, 2016 was lower than the same period in 2015, primarily due to the recognition of the penalty and the after-tax interest due on the asserted penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position, partially offset by increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

Nine months ended September 30, 2016 Compared to Nine months ended September 30, 2015. ComEd s Net income for the nine months ended September 30, 2016 was lower than the same period in 2015, primarily due to the recognition of the penalty and the after-tax interest due on the asserted penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position, partially offset by increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE) and favorable weather.

Operating Revenue Net of Purchased Power Expense

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.

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 and nine months ended September 30, 2016 and 2015, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
	70%	75%	72%	77%

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2016 and 2015 consisted of the following:

	September 30, 2016		September 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
	1,526,900	39%	1,664,600	43%

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 and nine months ended September 30, 2016, compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Weather	$ 38	$ 41
Volume	5	2
Electric distribution revenue	20	86
Transmission revenue	19	87
Regulatory required programs	(25)	(41)
Uncollectible accounts recovery, net	2	(15)
Pricing and customer mix	(11)	(5)
Other	9	17
Total increase	$ 57	$ 172

Table of Contents

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 and nine months ended September 30, 2016, favorable weather conditions increased Operating revenue net of purchased power expense when compared to the same periods 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 significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd s service territory for the three and nine months ended September 30, 2016 and 2015, consisted of the following:

Heating and Cooling Degree-Days				**% Change**	
Three Months Ended September 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	23	55	119	(58.2)%	(80.7)%
Cooling Degree-Days	840	634	613	32.5%	37.0%
Nine Months Ended September 30,					
Heating Degree-Days	3,678	4,373	4,048	(15.9)%	(9.1)%
Cooling Degree-Days	1,130	805	831	40.4%	36.0%

Volume. For the three and nine months ended September 30, 2016, Revenue net of purchased power expense increased as a result of higher delivery volume, exclusive of the effects of weather, reflecting increased average usage per residential customer as compared to the same periods 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, and allowed ROE. 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 and nine months ended September 30, 2016, ComEd recorded increased electric distribution revenue primarily due to increased capital investment and depreciation expense, partially offset by lower allowed ROE due to a decrease in treasury rates. See 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 the highest daily peak load, which is updated annually in January based on the prior calendar year. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. For the three and nine months ended September 30, 2016, ComEd recorded increased transmission revenue due to increased capital investment, higher depreciation expense and increased highest daily peak load as compared to the same period in 2015.

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.

Table of Contents

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. For the three and nine months ended September 30, 2016, the decrease in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to lower overall effective rates due to increased usage across all major customer classes and change in customer mix 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.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase	Nine Months Ended September 30,		Increase
	2016	2015	(Decrease)	2016	2015	(Decrease)
Operating and maintenance expense baseline	$ 336	$ 338	$ (2)	$ 993	$ 1,005	$ (12)
Operating and maintenance expense regulatory required programs[a]	41	66	$ (25)	120	161	(41)
Total operating and maintenance expense	$ 377	$ 404	$ (27)	$ 1,113	$ 1,166	$ (53)

(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 and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 3	$ (2)
Pension and non-pension postretirement benefits expense[a]	(6)	(16)
Storm-related costs	2	8
Uncollectible accounts expense provision[b]	3	4
Uncollectible accounts expense recovery, net[b]	(1)	(19)
BSC costs[c]	(2)	20
Other	(1)	(7)
	(2)	(12)
Regulatory required programs		
Energy efficiency and demand response programs	(25)	(41)
	(25)	(41)
Total increase (decrease)	$ (27)	$ (53)

(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 and nine

Table of Contents

months ended September 30, 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 and nine months ended September 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Depreciation expense[(a)]	$ 16	$ 43
Regulatory asset amortization	(1)	(7)
Other	5	10
Total increase	$ 20	$ 46

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

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 remained relatively consistent during the three and nine months ended September 30, 2016, compared to the same periods in 2015.

Gain on Sales of Assets

The increase in Gain on sales of assets during the three and nine months ended September 30, 2016, compared to the same periods in 2015, is primarily due to the sale of land during March 2016.

Interest Expense, Net

The changes in interest expense, net, for the three and nine months ended September 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Interest expense related to uncertain tax positions[(a)]	$ 106	$ 110
Interest expense on debt (including financing trusts)	11	20
Other	(3)	(4)
Increase in interest expense, net	$ 114	$ 126

(a) Primarily reflects the recognition of the after-tax interest due on the asserted penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Other, Net

The changes in other, net, for the three and nine months ended September 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Other income and deductions, net[(a)]	$ 89	$ 92
AFUDC equity	(4)	(6)
Other	(1)	
Increase in other, net	$ 84	$ 86

(a) Primarily reflects the recognition of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Effective Income Tax Rate

ComEd s effective income tax rate was 67.0% and 39.9% for the three months ended September 30, 2016 and 2015, respectively. ComEd s effective income tax rate was 45.1% and 40.0% for the nine months ended September 30, 2016 and 2015, respectively. The increase in the effective income tax rate for the three and nine months ended September 30, 2016 compared to the same periods in 2015 is primarily due to a non-deductible penalty. 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 GWhs)	Three Months Ended September 30, 2016	2015	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2016	2015	% Change	Weather-Normal % Change
Retail Deliveries[(a)]								
Residential	9,014	7,919	13.8%	1.0%	21,738	20,602	5.5%	(0.1)%
Small commercial & industrial	8,833	8,579	3.0%	(0.2)%	24,447	24,305	0.6%	(0.1)%
Large commercial & industrial	7,565	7,250	4.3%	2.0%	21,057	20,807	1.2%	1.0%
Public authorities & electric railroads	308	295	4.4%	4.4%	947	964	(1.8)%	(0.3)%
Total retail deliveries	25,720	24,043	7.0%	0.9%	68,189	66,678	2.3%	0.2%

Number of Electric Customers	As of September 30, 2016	2015
Residential	3,578,846	3,524,253
Small commercial & industrial	372,603	369,151
Large commercial & industrial	2,010	1,996
Public authorities & electric railroads	4,738	4,826

Total	3,958,197	3,900,226

Table of Contents

Electric Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[a]						
Residential	$ 786	$ 690	13.9%	$ 2,018	$ 1,785	13.1%
Small commercial & industrial	356	361	(1.4)%	1,007	1,029	(2.1)%
Large commercial & industrial	126	121	4.1%	350	339	3.2%
Public authorities & electric railroads	10	10	%	33	33	%
Total retail	1,278	1,182	8.1%	3,408	3,186	7.0%
Other revenue[b]	219	194	12.9%	623	523	19.1%
Total electric revenue[c]	$ 1,497	$ 1,376	8.8%	$ 4,031	$ 3,709	8.7%

(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.

(c) Includes operating revenues from affiliates totaling $4 million and $1 million for the three months ended September 30, 2016 and 2015, and $12 million and $3 million for the nine months ended September 30, 2016 and 2015, respectively.

Results of Operations PECO

	Three Months Ended September 30, 2016	2015	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2016	2015	Favorable (Unfavorable) Variance
Operating revenues	$ 788	$ 740	$ 48	$ 2,293	$ 2,386	$ (93)
Purchased power and fuel	272	278	6	809	953	144
Revenue net of purchased power and fuel[a]	516	462	54	1,484	1,433	51
Other operating expenses						
Operating and maintenance	199	196	(3)	604	609	5
Depreciation and amortization	67	68	1	201	198	(3)
Taxes other than income	46	44	(2)	126	125	(1)
Total other operating expenses	312	308	(4)	931	932	1
Gain on sales of assets					1	(1)
Operating income	204	154	50	553	502	51
Other income and (deductions)						
Interest expense, net	(30)	(28)	(2)	(92)	(84)	(8)
Other, net	2	1	1	6	3	3
Total other income and (deductions)	(28)	(27)	(1)	(86)	(81)	(5)

Income before income taxes	176	127	49	467	421	46
Income taxes	54	37	(17)	121	122	1
Net income attributable to common shareholder	$ 122	$ 90	$ 32	$ 346	$ 299	$ 47

(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

240

Table of Contents

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 September 30, 2016 Compared to Three Months Ended September 30, 2015. PECO s Net income attributable to common shareholder increased from the same period in 2015, primarily due to an increase in Revenue net of purchased power and fuel expense as a result of increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016, as well as favorable summer weather.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. PECO s Net income attributable to common shareholder increased from the same period in 2015, primarily due to an increase in Revenue net of purchased power and fuel expense as a result of increased electric distribution revenue pursuant to the 2015 PAPUC authorized electric distribution rate increase effective January 1, 2016, partially offset by unfavorable winter weather as well as a lower income tax expense as a result of an increase in the gas repairs deduction and a cumulative adjustment related to an anticipated gas repairs tax return accounting method change.

Operating Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO s electric supply and natural gas cost rates charged to customers are subject to adjustments 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 natural gas revenue net of purchased power and fuel expense.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The 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 natural 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 mmcf sales, respectively) for the three and nine months ended September 30, 2016 and 2015, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Electric	69%	69%	70%	69%
Natural Gas	31%	31%	26%	24%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2016 and 2015 consisted of the following:

	September 30, 2016		September 30, 2015	
	Number of customers	**% of total retail customers**	**Number of customers**	**% of total retail customers**
Electric	581,600	36%	558,300	35%
Natural Gas	81,300	16%	81,100	16%

Table of Contents

The changes in PECO s operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)			Nine Months Ended September 30, 2016 Increase (Decrease)		
	Electric	**Natural Gas**	**Total**	**Electric**	**Natural Gas**	**Total**
Weather	$ 31	$	$ 31	$ (19)	$ (28)	$ (47)
Volume	(2)		(2)	7	3	10
Pricing	36		36	137	(1)	136
Regulatory required programs	(9)		(9)	(43)		(43)
Other	(2)		(2)	(6)	1	(5)
Total increase (decrease)	$ 54	$	$ 54	$ 76	$ (25)	$ 51

Weather. The demand for electricity and natural gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended September 30, 2016 compared to the same period in 2015, Operating revenue net of purchased power and fuel expense was higher due to the impact of favorable weather conditions in PECO s service territory. During the nine months ended September 30, 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 weather conditions in PECO 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 30-year period in PECO s service territory. The changes in heating and cooling degree days in PECO s service territory for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	10		38	N/A	(73.7)%
Cooling Degree-Days	1,288	1,186	929	8.6%	38.6%
Nine Months Ended September 30,					
Heating Degree-Days	2,616	3,264	2,981	(19.9)%	(12.2)%
Cooling Degree-Days	1,684	1,699	1,278	(0.9)%	31.8%

Volume. Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three months ended September 30, 2016 compared to the same period in 2015, remained relatively consistent. The increase in Operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the nine months ended September 30, 2016 compared to the same periods in 2015, primarily reflects a shift in the volume profile across classes from lower priced classes to higher priced classes for electric, as well as the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for electric and natural gas.

Pricing. The increase in Operating revenues net of purchased power and fuel expense as a result of pricing for the three and nine months ended September 30, 2016 compared to the same periods 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.

Table of Contents

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 and nine months ended September 30, 2016 compared to the same periods in 2015 is primarily the result of smart meter costs reflected in base rates in 2016 in accordance with the 2015 PAPUC approved electric distribution rate case settlement effective January 1, 2016 versus through a rider mechanism in 2015. 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 September 30, 2016	Three Months Ended September 30, 2015	Increase (Decrease)	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Increase (Decrease)
Operating and maintenance expense baseline	$ 185	$ 170	$ 15	$ 545	$ 528	$ 17
Operating and maintenance expense regulatory required programs[(a)]	14	26	(12)	59	81	(22)
Total operating and maintenance expense	$ 199	$ 196	$ 3	$ 604	$ 609	$ (5)

(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.

The changes in Operating and maintenance expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine months ended September 30, 2016 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 8	$ 16
Storm-related costs	4	(9)
Pension and non-pension postretirement benefits expense	(1)	(3)
PHI merger and integration costs	1	3
BSC costs[(a)]	1	22
Uncollectible accounts expense	1	(12)
Other	1	
	15	17
Regulatory Required Programs		
Smart meter	(6)	(20)
Energy efficiency	(6)	(1)
Other		(1)
	(12)	(22)

Total decrease	$	3	$	(5)

(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 and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Depreciation and amortization expense	$	$ 2
Regulatory asset amortization	(1)	1
Total increase (decrease)	$ (1)	$ 3

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and nine months ended September 30, 2016 compared to the same periods in 2015 remained relatively consistent.

Interest Expense, Net

The increase in Interest expense, net for the three and nine months ended September 30, 2016 compared to the same periods 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 and nine months ended September 30, 2016 remained relatively consistent compared to the same periods in 2015.

Effective Income Tax Rate

PECO s effective income tax rate was 30.7% and 29.1% for the three months ended September 30, 2016 and 2015, respectively. PECO s effective income tax rate was 25.9% and 29.0% for the nine months ended September 30, 2016 and 2015, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2016 compared to the same period in 2015 is primarily due to an increase in the gas repairs deduction and a cumulative adjustment related to an anticipated gas repairs tax return accounting method change. 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.

Table of Contents

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	4,358	3,940	10.6%	1.5%	10,682	10,929	(2.3)%	1.3%
Small commercial & industrial	2,324	2,219	4.7%	0.5%	6,236	6,306	(1.1)%	1.7%
Large commercial & industrial	4,234	4,227	0.2%	(2.9)%	11,598	11,744	(1.2)%	(1.9)%
Public authorities & electric railroads	240	224	7.1%	7.1%	672	667	0.7%	0.7%
Total retail deliveries	11,156	10,610	5.1%	(0.4)%	29,188	29,646	(1.5)%	0.1%

Number of Electric Customers	As of September 30, 2016	2015
Residential	1,451,533	1,439,951
Small commercial & industrial	149,646	148,920
Large commercial & industrial	3,094	3,093
Public authorities & electric railroads	9,820	9,801
Total	1,614,093	1,601,765

Electric Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[(a)]						
Residential	$ 513	$ 461	11.3%	$ 1,278	$ 1,276	0.2%
Small commercial & industrial	109	113	(3.5)%	334	330	1.2%
Large commercial & industrial	59	58	1.7%	182	166	9.6%
Public authorities & electric railroads	8	8	%	25	23	8.7%
Total retail	689	640	7.7%	1,819	1,795	1.3%
Other revenue[(b)]	51	51	%	152	155	(1.9)%
Total electric revenue[(c)]	$ 740	$ 691	7.1%	$ 1,971	$ 1,950	1.1%

(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 primarily includes transmission revenue from PJM and wholesale electric revenue, in addition to rental income.
(c) Includes operating revenues from affiliates totaling $2 million and less than $1 million for the three months ended September 30, 2016 and 2015, respectively, and $5 million and less than $1 million for the nine months ended September 30, 2016 and 2015, respectively.

Table of Contents

PECO Natural Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change
Retail Delivery								
Retail sales[a]	3,494	3,639	(4.0)%	(2.4)%	38,488	45,734	(15.8)%	1.8%
Transportation and other	7,315	7,457	(1.9)%	(3.3)%	20,917	21,585	(3.1)%	1.1%
Total natural gas deliveries	10,809	11,096	(2.6)%	(3.0)%	59,405	67,319	(11.8)%	1.5%

Number of Natural Gas Customers	As of September 30, 2016	2015
Residential	470,024	465,023
Commercial & industrial	42,997	42,544
Total retail	513,021	507,567
Transportation	802	837
Total	513,823	508,404

Natural Gas Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales						
Retail sales[a]	$ 41	$ 42	(2.4)%	$ 298	$ 410	(27.3)%
Transportation and other	7	7	%	24	26	(7.7)%
Total natural gas revenues[b]	$ 48	$ 49	(2.0)%	$ 322	$ 436	(26.1)%

(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.

(b) Includes operating revenues from affiliates totaling less than $1 million for three months ended September 30, 2016 and $1 million for the three months ended September 30, 2015, and less than $1 million and $1 million for the nine months ended September 30, 2016 and 2015, respectively.

Table of Contents

Results of Operations BGE

	Three Months Ended September 30,		Favorable (Unfavorable)	Nine Months Ended September 30,		Favorable (Unfavorable)
	2016	2015	Variance	2016	2015	Variance
Operating revenues	$ 812	$ 725	$ 87	$ 2,421	$ 2,388	$ 33
Purchased power and fuel	360	311	(49)	994	1,037	43
Revenue net of purchased power and fuel[(a)]	452	414	38	1,427	1,351	76
Other operating expenses						
Operating and maintenance	178	169	(9)	588	499	(89)
Depreciation and amortization	101	79	(22)	307	271	(36)
Taxes other than income	58	57	(1)	172	169	(3)
Total other operating expenses	337	305	(32)	1,067	939	(128)
Gain on Sale of Assets		1	(1)		1	(1)
Operating income	115	110	5	360	413	(53)
Other income and (deductions)						
Interest expense, net	(28)	(25)	(3)	(76)	(73)	(3)
Other, net	5	4	1	16	13	3
Total other income and (deductions)	(23)	(21)	(2)	(60)	(60)	
Income before income taxes	92	89	3	300	353	(53)
Income taxes	36	35	(1)	109	141	32
Net income	56	54	2	191	212	(21)
Preference stock dividends	2	3	(1)	8	10	(2)
Net income attributable to common shareholder	$ 54	$ 51	$ 3	$ 183	$ 202	$ (19)

(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 September 30, 2016 Compared to Three Months Ended September 30, 2015. BGE s Net income attributable to common shareholder for the three months ended September 30, 2016 was higher than the same period in 2015, primarily due to an increase in Revenue net of purchased power and fuel, primarily as a result of an increase in transmission formula rate revenues, and higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016. The increase in Revenue net of purchased power and fuel was partially offset by an increase in Depreciation and amortization expense due to the initiation of cost recovery of the AMI programs under the distribution rate orders issued by the MDPSC in June 2016 and July 2016.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. BGE s Net income attributable to common shareholder for the nine months ended September 30, 2016 was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense as a result of reducing certain regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the final smart grid rate order issued by the MDPSC in June 2016 and increased storm costs. The lower net income was also due to an increase in Depreciation and amortization expense due to the initiation of cost recovery of the AMI programs under the distribution rate orders issued by the MDPSC in June 2016 and July 2016. These increases in Operating and maintenance expense and Depreciation and amortization expense were partially offset by an increase in Revenue net of purchased power and fuel, primarily as a result of an increase in transmission formula rate revenues, higher electric and natural gas revenues as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016, and lower income tax expense driven by lower taxable income.

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 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.

Electric and natural gas revenue and purchased power and fuel expense are also affected by fluctuations in the number of customers electing to use a competitive electric generation or natural gas supplier. All BGE customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers choice of suppliers does not impact the volume of deliveries, but does affect revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2016 and 2015, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Electric	58%	60%	59%	59%
Natural Gas	80%	76%	59%	54%

The number of retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2016 and 2015 consisted of the following:

	September 30, 2016		September 30, 2015	
	Number of Customers	% of total retail customers	Number of customers	% of total retail customers
Electric	334,100	26%	346,400	28%
Natural Gas	150,000	23%	154,900	24%

Table of Contents

The changes in BGE s operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)			Nine Months Ended September 30, 2016 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 16	$ 4	$ 20	$ 22	$ 5	$ 27
Regulatory required programs	6		6	6		6
Transmission revenue	8		8	28		28
Other, net	4		4	20	(5)	15
Total increase	$ 34	$ 4	$ 38	$ 76	$	$ 76

Distribution Rate Increase. The increase in distribution revenues for the three and nine months ended September 30, 2016, compared to the same periods in 2015, was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in June 2016 and July 2016 in accordance with the MDPSC approved electric and natural gas distribution rate case orders. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and usage conditions. The MDPSC allows BGE to record a monthly adjustment to its electric and natural gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service natural gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE s electric and natural gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in actual 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 (i.e., increase in the number of customers), it will not be affected by actual weather or usage conditions (i.e., changes in consumption per customer). BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE s service territory. The changes in heating and cooling degree days in BGE s service territory for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

Heating and Cooling Degree-Days	2016	2015	Normal	% Change 2016 vs. 2015	% Change 2016 vs. Normal
Three Months Ended September 30,					
Heating Degree-Days	24	46	79	(47.8)%	(69.6)%
Cooling Degree-Days	747	592	594	26.2%	25.8%
Nine Months Ended September 30,					
Heating Degree-Days	2,878	3,418	2,999	(15.8)%	(4.0)%
Cooling Degree-Days	966	909	851	6.3%	13.5%

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. 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.

Table of Contents

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 and nine months ended September 30, 2016 compared to the same periods in 2015, the increase in transmission revenue was primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net. Other net revenue, which can vary from period to period, includes commodity electric and gas revenue and other miscellaneous revenue such as service application and late payment fees; partially offset by commodity electric and gas purchased fuel and energy.

Operating and Maintenance Expense

The changes in operating and maintenance expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Impairment on long-lived assets and losses on regulatory assets[a]	$	$ 52
Storm-related costs	1	19
Uncollectible accounts expense[b]	4	(4)
City of Baltimore conduit fees[c]	7	22
BSC costs[d]	(2)	8
Other	(1)	(8)
Total increase	$ 9	$ 89

(a) See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Uncollectible accounts increased primarily due to the impact of warmer third quarter weather conditions for the three months ended September 30, 2016 compared to the same period in 2015. Uncollectible accounts decreased primarily due to milder weather and improved customer behavior for the nine months ended September 30, 2016 compared to the same periods in 2015.
(c) City of Baltimore conduit fees increased for the three and nine months ended September 30, 2016 compared to the same periods 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.
(d) Primarily reflects decreased information technology support during the three months ended September 30, 2016 compared to the same period in 2015 and increased information technology support services and executive services from BSC during the nine months ended September 30, 2016 compared to the same period in 2015.

Depreciation and Amortization

The changes in depreciation and amortization expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, 2016 Increase (Decrease)	Nine Months Ended September 30, 2016 Increase (Decrease)
Depreciation expense[a]	$ 1	$ 8

Regulatory asset amortization[b]		21		28
Total increase	$	22	$	36

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

250

Table of Contents

(b) Regulatory asset amortization increased for the three and nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to an increase in regulatory asset amortization related to energy efficiency programs and the initiation of cost recovery of the AMI programs under the final electric and natural gas distribution rate case order issued by the MDPSC in June 2016. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Taxes Other Than Income

Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three and nine months ended September 30, 2016 compared to the same periods in 2015 remained relatively consistent.

Interest Expense, Net

Interest expense, net increased during the three and nine months ended September 30, 2016, compared to the same periods in 2015 due to higher outstanding debt.

Effective Income Tax Rate

BGE s effective income tax rate was 39.1% and 39.3% for the three months ended September 30, 2016 and 2015, respectively. BGE s effective income tax rate was 36.3% and 39.9% for the nine months ended September 30, 2016 and 2015, respectively. The decrease in the effective income tax rate for the nine months ended September 30, 2016 compared to the same periods in 2015, is primarily due a lower taxable income and a cumulative adjustment to tax expense pending anticipated recovery from transmission customers. 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.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	3,900	3,458	12.8%	n.m.	9,996	10,266	(2.6)%	n.m.
Small commercial & industrial	877	788	11.3%	n.m.	2,343	2,413	(2.9)%	n.m.
Large commercial & industrial	3,992	3,829	4.3%	n.m.	10,627	10,735	(1.0)%	n.m.
Public authorities & electric railroads	72	75	(4.0)%	n.m.	215	224	(4.0)%	n.m.
Total electric deliveries	8,841	8,150	8.5%	n.m.	23,181	23,638	(1.9)%	n.m.

Number of Electric Customers	As of September 30, 2016	As of September 30, 2015
Residential	1,145,020	1,132,836
Small commercial & industrial	112,609	112,888
Large commercial & industrial	12,030	11,863
Public authorities & electric railroads	282	286
Total	1,269,941	1,257,873

Electric Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[(a)]						
Residential	$ 451	$ 379	19.0%	$ 1,203	$ 1,131	6.4%
Small commercial & industrial	74	70	5.7%	212	208	1.9%
Large commercial & industrial	123	122	0.8%	337	351	(4.0)%
Public authorities & electric railroads	9	9	%	27	24	12.5%
Total retail	657	580	13.3%	1,779	1,714	3.8%
Other revenue[(b)]	78	75	4.0%	219	194	12.9%
Total electric revenue	$ 735	$ 655	12.2%	$ 1,998	$ 1,908	4.7%

(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.

(b) Includes operating revenues from affiliates totaling $1 million and $5 million for the three and nine months ended September 30, 2016.

BGE Natural Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Retail sales	13,159	11,719	12.3%	n.m.	69,415	72,481	(4.2)%	n.m.
Transportation and other[(b)]	1,311	612	114.2%	n.m.	4,078	4,521	(9.8)%	n.m.
Total natural gas deliveries	14,470	12,331	17.3%	n.m.	73,493	77,002	(4.6)%	n.m.

Number of Gas Customers	As of September 30, 2016	2015
Residential	619,837	613,571
Commercial & industrial	43,957	43,885
Total	663,794	657,456

Natural Gas Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[(a)]						
Retail sales	$ 71	$ 66	7.6%	$ 403	$ 450	(10.4)%
Transportation and other[(b)]	6	4	50.0%	20	30	(33.3)%
Total natural gas revenues[(c)]	$ 77	$ 70	10.0%	$ 423	$ 480	(11.9)%

(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 1,311 mmcfs ($4 million) and 612 mmcfs ($3 million) for the three months ended September 30, 2016 and 2015, respectively. Transportation and other gas revenue includes off-system revenue of 4,078 mmcfs ($14 million) and 4,521 mmcfs ($28 million) for the nine months ended September 30, 2016 and 2015, respectively.
(c) Includes operating revenues from affiliates totaling $6 million and $3 million for the three months ended September 30, 2016 and 2015, respectively, and $11 million for the nine months ended September 30, 2016 and 2015.

Table of Contents

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.

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 and nine months ended September 30, 2015 and for the period from January 1, 2016 to March 23, 2016. The Successor reporting periods represent PHI s results of operations for the three months ended September 30, 2016 and for the period from March 24, 2016 to September 30, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Successor	*Predecessor*	*Successor*	*Predecessor*	
	Three Months Ended September 30, 2016	**Three Months Ended September 30, 2015**	**March 24, 2016 to September 30, 2016**	**January 1, 2016 to March 23, 2016**	**Nine Months Ended September 30, 2015**
Operating revenues	$ 1,394	$ 1,336	$ 2,565	$ 1,153	$ 3,809
Purchased power and fuel	583	579	1,037	497	1,646
Revenue net of purchased power and fuel[(a)]	811	757	1,528	656	2,163
Other operating expenses					
Operating and maintenance	226	287	921	294	875
Depreciation and amortization	182	166	355	152	474
Taxes other than income	124	120	248	105	349
Total other operating expenses	532	573	1,524	551	1,698
Operating income	279	184	4	105	465
Other income and (deductions)					
Interest expense, net	(64)	(71)	(135)	(65)	(211)
Other, net	19	27	31	(4)	48
Total other income and (deductions)	(45)	(44)	(104)	(69)	(163)
Income (loss) before income taxes	234	140	(100)	36	302
Income taxes	68	49	(9)	17	105
Net income (loss) attributable to membership interest/common shareholders	$ 166	$ 91	$ (91)	$ 19	$ 197

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power and fuel expense for electric and natural gas sales. PHI believes revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Successor Period Three Months Ended September 30, 2016

PHI s net income attributable to common shareholders for the Successor period of three months ended September 30, 2016 was $166 million. There were no significant changes in the underlying trends affecting

Table of Contents

PHI s operations during the Successor period of three months ended September 30, 2016 except for the pre-tax recording of a $50 million reduction of merger-related commitments within Operating and maintenance expense reflecting a reallocation of the most favored nation commitments among Exelon and Pepco, DPL and ACE, such that more commitments are expected to be obligations of Exelon for energy efficiency, workforce development and other programs as opposed to obligations of Pepco, DPL and ACE for additional customer rate credits.

Successor Period Three Months Ended September 30, 2016 Compared to the Predecessor Period Three Months Ended September 30, 2015

Net Income Attributable to Common Shareholders

PHI s net income attributable to common shareholders was $166 million for the three months ended September 30, 2016 as compared to $91 million for the three months ended September 30, 2015.

Operating 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, increased by $54 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. The increase is attributable to the following factors:

- Increase of $30 million at Pepco primarily related to electric distribution revenue increases totaling $9 million due to customer growth, $18 million in required regulatory programs primarily due to an EmPower Maryland rate increase effective February 2015, and $3 million higher transmission revenue due to a higher rate effective June 1, 2015 and due to the establishment of reserves recorded in September 2015 related to the FERC ROE challenges, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016;

- Increase of $18 million at DPL primarily related to electric distribution revenue increases totaling $7 million due to customer growth and higher weather-related sales, an increase of $6 million due to an EmPower Maryland rate increase effective February 2015, and $5 million higher transmission revenue due to a higher rate effective June 1, 2015 and due to the establishment of a reserve recorded in September 2015 related to the FERC ROE challenges, partially offset by lower revenue related to the MAPP abandonment recovery period ending March 2016;

- Increase of $28 million at ACE primarily related to electric distribution revenue increases totaling $17 million due to higher average customer usage and a rate increase effective August 2016 and $11 million higher transmission revenue due to a higher rate effective June 1, 2015 and due to the establishment of a reserve recorded in September 2015 related to the FERC ROE challenges;

- Increase of $13 million due to the effects of a decrease in ACE s BGS unbilled revenue resulting from lower average customer usage in the third quarter 2015;

- Increase of $11 million at Corporate primarily due to BSC inter-company transactions; and

- Decrease of $46 million at PES due to PHI s results of operations including the results of PES in 2015 and not in 2016.

Operating and Maintenance Expense

Operating and maintenance expense decreased by $61 million for the three months ended September 30, 2016 as compared to the three months ended September 30, 2015. The decrease is attributable to the following factors:

Decrease of $27 million at Pepco, DPL and ACE primarily due to a $50 million reduction of merger-related commitments reflecting a reallocation of the most favored nation commitments among Exelon and Pepco, DPL and ACE, such that more commitments are expected to be obligations of Exelon for energy efficiency, workforce development and other programs as opposed to obligations of Pepco, DPL and ACE for additional customer rate credits, partially offset by $13 million of higher BSC and PHISCO allocations, $4 million of charges resulting from a remeasurement of AMI-related regulatory assets and $3 million of higher storm costs;

Increase of $12 million at Corporate primarily due to BSC inter-company and purchase accounting transactions; and

Decrease of $46 million at PES due to PHI s results of operations including the results of PES in 2015 and not in 2016.

Depreciation and Amortization Expense

Depreciation and amortization expense increased by $16 million primarily due to $8 million higher amortization of regulatory assets due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs, and higher depreciation of $6 million due to ongoing capital expenditures at Pepco, DPL, and ACE.

Taxes Other Than Income

Taxes other than income increased by $4 million primarily due to higher utility taxes that are collected and passed through by Pepco and DPL.

Interest Expense, Net

Interest expense decreased by $7 million primarily due to purchase accounting entries related to the fair value of long-term debt.

Other, Net

Other, net for the three months ended September 30, 2016 decreased by $8 million due to $15 million of income recorded in September 2015 from a change in the fair value of the derivative related to preferred stock, partially offset by higher AFUDC income in 2016.

Effective Income Tax Rate

PHI s effective income tax rates for the three months ended September 30, 2016 and 2015 were 29.1% and 35.0%, 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.

Successor Period March 24, 2016 to September 30, 2016

PHI s net loss attributable to common shareholders for the Successor period of March 24, 2016 to September 30, 2016 was $(91) million. There were no significant changes in the underlying trends affecting PHI s operations during the Successor period of March 24, 2016 to September 30, 2016 except for the pre-tax recording of $375 million of non-recurring merger-related costs within Operating and maintenance expense.

PHI s effective income tax rate for the Successor period of March 24, 2016 to September 30, 2016 was 9.0%. 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.

Predecessor Period January 1, 2016 to March 23, 2016

PHI s net income attributable to common shareholders for the Predecessor period of January 1, 2016 to March 23, 2016 was $19 million. There were no significant changes in the underlying trends affecting PHI s

Table of Contents

operations during the Predecessor period of January 1, 2016 to March 23, 2016 except for the pre-tax recording of $29 million of non-recurring merger-related costs within Operating and maintenance expense and $18 million of preferred stock derivative expense within Other, net.

PHI s effective income tax rate for the Predecessor period of January 1, 2016 to March 23, 2016 was 47.2%. 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.

Predecessor Period January 1, 2015 to September 30, 2015

PHI s net income attributable to common shareholders for the Predecessor period of the nine months ended September 30, 2015 was $197 million. There were no significant changes in the underlying trends affecting PHI s operations during the Predecessor period of the nine months ended September 30, 2015 except for the pre-tax recording of $37 million of implementation and support costs due to the completion of a new customer information system and $16 million of non-recurring merger-related costs within Operating and maintenance expense and $15 million of income due to a change in the fair value of the derivative related to preferred stock within Other, net.

PHI s effective income tax rate for the nine months ended September 30, 2015 was 34.8%. 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 September 30, 2016	Three Months Ended September 30, 2015	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Favorable (Unfavorable) Variance
Operating revenues	$ 635	$ 592	$ 43	$ 1,695	$ 1,641	$ 54
Purchased power expense	213	200	(13)	563	573	10
Revenue net of purchased power expense[(a)]	422	392	30	1,132	1,068	64
Other operating expenses						
Operating and maintenance	109	111	2	508	327	(181)
Depreciation and amortization	76	66	(10)	221	191	(30)
Taxes other than income	105	100	(5)	287	289	2
Total other operating expenses	290	277	(13)	1,016	807	(209)
Gain on sale of assets				8		8
Operating income	132	115	17	124	261	(137)
Other income and (deductions)						
Interest expense, net	(30)	(31)	1	(98)	(92)	(6)
Other, net	12	8	4	28	21	7
Total other income and (deductions)	(18)	(23)	5	(70)	(71)	1
Income before income taxes	114	92	22	54	190	(136)
Income taxes	35	32	(3)	34	62	28
Net income attributable to common shareholder	$ 79	$ 60	$ 19	$ 20	$ 128	$ (108)

(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

Table of Contents

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 September 30, 2016 Compared to Three Months Ended September 30, 2015. Pepco s net income attributable to common shareholder for the three months ended September 30, 2016, was higher than the same period in 2015, primarily due to an increase in revenue net of purchased power expense resulting from customer growth and and due to a decrease in operating and maintenance expense reflecting a revision in the estimate of Pepco s merger commitment costs associated with the most favored nation provision of the merger orders. The revision in estimate included a reduction in Pepco s merger commitment costs of $13 million, reflecting a reallocation of the most favored nation commitments among Exelon and Pepco, such that more commitments are expected to be obligations of Exelon for energy efficiency and other programs as opposed to obligations of Pepco for additional customer rate credits.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. Pepco s net income attributable to common shareholder for the nine months ended September 30, 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.

Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Electric	63%	65%	65%	64%

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2016 and 2015 consisted of the following:

	September 30, 2016		September 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	175,960	21%	158,601	19%

Retail deliveries purchased from competitive electric generation suppliers represented 71% and 72% of Pepco s retail kWh sales to the District of Columbia customers and 58% and 59% of Pepco s retail kWh sales to

Table of Contents

Maryland customers for the three and nine months ended September 30, 2016 and 71% and 70% of Pepco s retail kWh sales to the District of Columbia customers and 61% and 59% of Pepco s retail kWh sales to Maryland customers for the three and nine months ended September 30, 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 and nine months ended September 30, 2016 compared to the same period in 2015 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Volume	$ 8	$ 22
Regulatory required programs	18	36
Transmission revenue	3	3
Other	1	3
Total increase	$ 30	$ 64

Revenue Decoupling. Pepco s results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of Pepco in Maryland and in the District of Columbia, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland and the District of Columbia to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

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.

Table of Contents

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in Pepco s service territory. The changes in heating and cooling degree days in Pepco s service territory for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

				% Change	
Three Months Ended September 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	1		13	%	(92.3)%
Cooling Degree-Days	1,418	1,239	1,109	14.4%	27.9%
Nine Months Ended September 30,					
Heating Degree-Days	2,408	2,691	2,507	(10.5)%	(3.9)%
Cooling Degree-Days	1,872	1,914	1,587	(2.2)%	18.0%

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 and nine months ended September 30, 2016 compared to the same periods in 2015, primarily reflects the impact of 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 other taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

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 adjustments. The increase in revenue net of purchased power expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses and due to the establishment of a reserve recorded in September 2015 related to the FERC ROE challenges, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016.

Operating and Maintenance Expense

	Three Months Ended September 30,		Increase	Nine Months Ended September 30,		Increase
	2016	**2015**	**(Decrease)**	**2016**	**2015**	**(Decrease)**
Operating and maintenance expense baseline	$ 106	$ 107	$ (1)	$ 500	$ 318	$ 182
Operating and maintenance expense regulatory required programs[(a)]	3	4	(1)	8	9	(1)
Total operating and maintenance expense	$ 109	$ 111	$ (2)	$ 508	$ 327	$ 181

(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.

Table of Contents

The changes in operating and maintenance expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 1	$ 6
Storm-related costs	2	5
Remeasurement of AMI-related regulatory asset	4	11
Deferral of merger-related costs to regulatory asset	(1)	(10)
BSC and PHISCO allocations[a]	6	41
Merger commitments[b]	(13)	126
Other		3
	(1)	182
Regulatory required programs		
Purchased power administrative costs	(1)	(1)
	(1)	(1)
Total (decrease) increase	$ (2)	$ 181

(a) Primarily related to merger severance and compensation costs.
(b) Primarily related to merger-related commitments for customer rate credits, inclusive of the estimate of merger commitment costs associated with the most favored nation provision of the merger orders, and charitable contributions.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Depreciation expense[a]	$ 2	$ 6
Regulatory asset amortization[b]	8	24
Total increase	$ 10	$ 30

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the three and nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs.

Taxes Other Than Income

Taxes other than income for the three months ended September 30, 2016 compared to the same period in 2015 increased primarily due to higher utility taxes that are collected and passed through by Pepco. Taxes other than income for the nine months ended September 30, 2016 compared to the same period in 2015 decreased primarily due to lower property taxes in Maryland partially offset by higher utility taxes that are collected and passed through by Pepco.

Gain on Sale of Assets

Gain on sale of assets for the nine months ended September 30, 2016 compared to the same period in 2015 increased due to a second quarter 2016 gain recorded from the sale of land.

Interest Expense, Net

Interest expense, net for the nine months ended September 30, 2016 compared to the same period in 2015 increased $6 million primarily due to the recording of interest expense for an uncertain tax position in the first quarter of 2016.

Other, Net

Other, net for the three and nine months ended September 30, 2016 compared to the same periods in 2015 increased primarily due to higher income from AFUDC.

Effective Income Tax Rate

Pepco s effective income tax rate was 30.7% and 34.8% for three months ended September 30, 2016 and 2015, respectively. Pepco s effective income tax rate was 63.0% and 32.6% for the nine months ended September 30, 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 $30 million during the nine months ended September 30, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

Pepco Electric Operating Statistics and Revenue Detail

	Three Months Ended September 30,			Weather - Normal	Nine Months Ended September 30,			Weather - Normal
Retail Deliveries to Customers (in GWhs)	**2016**	**2015**	**% Change**	**% Change**	**2016**	**2015**	**% Change**	**% Change**
Retail Deliveries[(a)]								
Residential	2,675	2,355	13.6%	11.0%	6,652	6,844	(2.8)%	3.1%
Small commercial & industrial	394	379	4.0%	5.3%	1,124	1,150	(2.3)%	1.4%
Large commercial & industrial	4,314	4,254	1.4%	4.8%	11,890	11,759	1.1%	1.4%
Public authorities & electric railroads	180	177	1.7%	1.1%	544	540	0.7%	%
Total retail deliveries	7,563	7,165	5.6%	6.9%	20,210	20,293	(0.4)%	1.9%

	As of September 30,	
Number of Electric Customers	**2016**	**2015**
Residential	775,911	749,662
Small commercial & industrial	53,425	53,459
Large commercial & industrial	21,315	20,820
Public authorities & electric railroads	129	128
Total	850,780	824,069

Table of Contents

Electric Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[a]						
Residential	$ 315	$ 285	10.5%	$ 791	$ 769	2.9%
Small commercial & industrial	43	43	%	116	116	%
Large commercial & industrial	219	210	4.3%	613	590	3.9%
Public authorities & electric railroads	7	7	%	23	23	%
Total retail	584	545	7.2%	1,543	1,498	3.0%
Other revenue[b]	51	47	8.5%	152	143	6.3%
Total electric revenue[c]	$ 635	$ 592	7.3%	$ 1,695	$ 1,641	3.3%

(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.

(c) Includes operating revenues from affiliates totaling $1 million and $1 million for the three months ended September 30, 2016 and 2015, respectively, and $3 million and $4 million for the nine months ended September 30, 2016 and 2015, respectively.

Results of Operations DPL

	Three Months Ended September 30, 2016	2015	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2016	2015	Favorable (Unfavorable) Variance
Operating revenues	$ 331	$ 314	$ 17	$ 974	$ 1,004	$ (30)
Purchased power and fuel	150	151	1	448	500	52
Revenue net of purchased power and fuel[a]	181	163	18	526	504	22
Other operating expenses						
Operating and maintenance	55	77	22	338	234	(104)
Depreciation, amortization and accretion	44	40	(4)	120	113	(7)
Taxes other than income	14	14		42	39	(3)
Total other operating expenses	113	131	18	500	386	(114)
Gain on sale of asset	4		4	4		4
Operating income	72	32	40	30	118	(88)
Other income and (deductions)						
Interest expense, net	(12)	(12)		(37)	(37)	
Other, net	3	4	(1)	9	8	1
Total other income and (deductions)	(9)	(8)	(1)	(28)	(29)	1
Income before income taxes	63	24	39	2	89	(87)
Income taxes	19	9	(10)	18	34	16

Net income (loss) attributable to common shareholder	$ 44	$ 15	$ 29	$ (16)	$ 55	$ (71)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for natural gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income (Loss) Attributable to Common Shareholder

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. DPL s net income attributable to common shareholder for the three months ended September 30, 2016, was higher than the same period in 2015 as a result of an increase in revenue net of purchased power expense primarily resulting from customer growth and higher transmission revenue and due to a decrease in operating and maintenance expense reflecting a revision in the estimate of DPL s merger commitment costs associated with the most favored nation provision of the merger orders. The revision in estimate included a reduction in DPL s merger commitment costs of $27 million, reflecting a reallocation of the most favored nation commitments among Exelon and DPL, such that more commitments are expected to be obligations of Exelon for energy efficiency and other programs as opposed to obligations of DPL for additional customer rate credits.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. DPL s net loss attributable to common shareholder for the nine months ended September 30, 2016, compared unfavorably to DPL s net income for 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 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 natural gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers, respectively. The customers choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2016 and 2015, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	**2015**	**2016**	**2015**
Electric	49%	52%	51%	50%
Natural Gas	51%	51%	32%	31%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2016 and 2015 consisted of the following:

	September 30, 2016		September 30, 2015	
	Number of customers	**% of total retail customers**	**Number of customers**	**% of total retail customers**
Electric	79,501	15.4%	78,545	15.3%
Natural Gas	157	0.1%	159	0.1%

Table of Contents

Retail deliveries purchased from competitive electric generation suppliers represented 51% and 53% of DPL s retail kWh sales to Delaware customers and 47% and 47% of DPL retail kWh sales to Maryland customers for the three and nine months ended September 30, 2016 and 54% and 51% and to Delaware customers and 49% and 46% and to Maryland customers for the three and nine months ended September 30, 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 and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)			Nine Months Ended September 30, Increase (Decrease)		
	Electric	**Gas**	**Total**	**Electric**	**Gas**	**Total**
Weather	$ 4	$	$ 4	$ (4)	$ (5)	$ (9)
Volume	2		2	8	2	10
Regulatory required programs	6		6	7		7
Transmission revenue	5		5	12		12
Other	1		1	2		2
Total increase (decrease)	$ 18	$	$ 18	$ 25	$ (3)	$ 22

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.

264

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 natural gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the three months ended September 30, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was higher due to the impact of favorable summer weather conditions in DPL s service territory. During the nine months ended September 30, 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 DPL s service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL s electric service territory and a 30-year period in DPL s natural gas service territory. The changes in heating and cooling degree days in DPL s service territory for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and normal weather consisted of the following:

				% Change	
Three Months Ended September 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	14	2	35	600.0%	(60.0)%
Cooling Degree-Days	1,103	897	836	23.0%	31.9%
Nine Months Ended September 30,					
Heating Degree-Days	2,812	3,275	2,974	(14.1)%	(5.4)%
Cooling Degree-Days	1,410	1,315	1,164	7.2%	21.1%

Volume. The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2016 compared to the same periods 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. 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 adjustments. The increase in revenue net of purchased power expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses and due to the establishment of a reserve recorded in September 2015 related to the FERC ROE challenges, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016.

Table of Contents

Operating and Maintenance Expense

	Three Months Ended September 30, 2016	2015	Increase (Decrease)	Nine Months Ended September 30, 2016	2015	Increase (Decrease)
Operating and maintenance expense baseline	$ 50	$ 74	$ (24)	$ 328	$ 222	$ 106
Operating and maintenance expense regulatory required programs[a]	5	3	2	10	12	(2)
Total operating and maintenance expense	$ 55	$ 77	$ (22)	$ 338	$ 234	$ 104

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (3)	$ (4)
Storm-related costs	1	4
Uncollectible accounts expense	(2)	(5)
Remeasurement of AMI-related regulatory asset	1	2
Deferral of merger-related costs to regulatory asset		(3)
Write-off of construction work in progress		4
BSC and PHISCO allocations[a]	5	24
Merger commitments[b]	(27)	77
Other	1	7
	(24)	106
Regulatory required programs		
Purchased power administrative costs	2	(2)
Total (decrease) increase	$ (22)	$ 104

(a) Primarily related to merger severance and compensation costs.
(b) Primarily related to merger-related commitments for customer rate credits, inclusive of the estimate of merger commitment costs associated with the most favored nation provision of the merger orders, and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)		Nine Months Ended September 30, Increase (Decrease)	
Depreciation expense[a]	$	2	$	6
Regulatory asset amortization[b]		1		2
Delaware renewable energy portfolio standards deferral		1		(1)
Total increase	$	4	$	7

Table of Contents

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the three and nine months ended September 30, 2016 compared to the same periods in 2015 due to an EmPower Maryland surcharge rate increase effective February 2015, partially offset by lower amortization of MAPP abandonment costs.

Taxes Other Than Income

Taxes other than income for the nine months ended September 30, 2016 compared to the same period in 2015 increased primarily due to higher property taxes.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2016 compared to the same periods in 2015 remained relatively constant.

Other, Net

Other, net for the three and nine months ended September 30, 2016 remained relatively level compared to the same periods in 2015.

Effective Income Tax Rate

DPL s effective income tax rate was 30.2% and 37.5% for the three months ended September 30, 2016 and 2015, respectively. DPL s effective income tax rate was 900.0% and 38.2% for the nine months ended September 30, 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 $19 million during the nine months ended September 30, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

DPL Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	% Change	Weather - Normal % Change
Retail Deliveries[a]								
Residential	1,601	1,425	12.4%	9.9%	4,066	4,297	(5.4)%	1.9%
Small commercial & industrial	642	618	3.9%	7.7%	1,746	1,803	(3.2)%	2.6%
Large commercial & industrial	1,250	1,283	(2.6)%	4.1%	3,492	3,550	(1.6)%	1.2%
Public authorities & electric railroads	9	11	(18.2)%	7.6%	35	33	6.1%	(3.7)%
Total retail deliveries	3,502	3,337	4.9%	7.3%	9,339	9,683	(3.6)%	1.8%

Number of Electric Customers	As of September 30, 2016	As of September 30, 2015
Residential	455,640	453,114
Small commercial & industrial	60,034	59,583
Large commercial & industrial	1,414	1,412
Public authorities & electric railroads	643	644
Total	517,731	514,753

267

Table of Contents

Electric Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[(a)]						
Residential	$ 200	$ 181	10.5%	$ 522	$ 533	(2.1)%
Small commercial & industrial	48	51	(5.9)%	143	145	(1.4)%
Large commercial & industrial	24	26	(7.7)%	74	79	(6.3)%
Public authorities & electric railroads	2	3	(33.3)%	9	9	%
Total retail	274	261	5.0%	748	766	(2.3)%
Other revenue[(b)]	40	34	17.6%	124	109	13.8%
Total electric revenue[(c)]	$ 314	$ 295	6.4%	$ 872	$ 875	(0.3)%

(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.
(c) Includes operating revenues from affiliates totaling $2 million and $1 million for the three months ended September 30, 2016 and 2015, respectively, and $6 million and $4 million for the nine months ended September 30, 2016 and 2015, respectively.

DPL Natural Gas Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	2015	% Change	Weather - Normal % Change
Retail Deliveries								
Residential	1,121	1,111	0.9%	(5.1)%	9,253	10,720	(13.7)%	(4.1)%
Transportation & other	1,166	1,144	1.9%	(0.6)%	4,455	4,716	(5.5)%	(0.9)%
Total natural gas deliveries	2,287	2,255	1.4%	(2.8)%	13,708	15,436	(11.2)%	(3.1)%

Number of Gas Customers	As of September 30, 2016	2015
Residential	120,075	119,006
Commercial & industrial	9,656	9,527
Transportation & other	157	159
Total	129,888	128,692

Natural Gas Revenue	Three Months Ended September 30, 2016	2015	% Change	Nine Months Ended September 30, 2016	2015	% Change
Retail Sales[(a)]						
Retail sales	$ 13	$ 13	%	$ 87	$ 111	(21.6)%
Transportation & other[(b)]	4	6	(33.3)%	15	18	(16.7)%
Total natural gas revenues	$ 17	$ 19	(10.5)%	$ 102	$ 129	(20.9)%

(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 September 30, 2016	2015	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2016	2015	Favorable (Unfavorable) Variance
Operating revenues	$ 421	$ 386	$ 35	$ 982	$ 1,003	$ (21)
Purchased power expense	221	214	(7)	520	552	32
Revenue net of purchased power expense[(a)]	200	172	28	462	451	11
Other operating expenses						
Operating and maintenance	67	70	3	346	207	(139)
Depreciation, amortization and accretion	49	49		130	135	5
Taxes other than income	1	2	1	6	5	(1)
Total other operating expenses	117	121	4	482	347	(135)
Gain on sale of assets				1		1
Operating income (loss)	83	51	32	(19)	104	(123)
Other income and (deductions)						
Interest expense, net	(15)	(16)	1	(47)	(48)	1
Other, net	2	1	1	8	4	4
Total other income and (deductions)	(13)	(15)	2	(39)	(44)	5
Income (loss) before income taxes	70	36	34	(58)	60	(118)
Income taxes	23	14	(9)	(8)	23	31
Net income (loss) attributable to common shareholder	$ 47	$ 22	$ 25	$ (50)	$ 37	$ (87)

(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 (Loss) Attributable to Common Shareholder

Three Months Ended September 30, 2016 Compared to Three Months Ended September 30, 2015. ACE s net income attributable to common shareholder for the three months ended September 30, 2016, was higher than the same period in 2015, primarily due to an increase in operating revenue net of purchased power expense resulting from higher average customer usage and higher transmission revenue and due to a decrease in operating and maintenance expense reflecting a revision in the estimate of ACE s merger commitment costs associated with the most favored nation provision of the merger orders. The revision in estimate included a reduction in ACE s merger commitment costs of $10 million, reflecting a reallocation of the most favored nation commitments among Exelon and ACE, such that more commitments are expected to be obligations of Exelon for energy efficiency and other programs as opposed to obligations of ACE for additional customer rate credits.

Nine Months Ended September 30, 2016 Compared to Nine Months Ended September 30, 2015. ACE s net loss attributable to common shareholder for the nine months ended September 30, 2016, compared unfavorably to ACE s net income for the same period in 2015, primarily due to an increase in operating and maintenance expense due to merger-related costs.

Table of Contents

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.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2016, compared to the same periods in 2015, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	2016	2015
Electric	44%	40%	46%	44%

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2016 and 2015 consisted of the following:

	September 30, 2016		September 30, 2015	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	96,837	18%	78,758	14%

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 contacts with unaffiliated NUGs, and revenue from transmission enhancement credits.

Operating revenues also include work and services performed on behalf of customers, including other utilities, which is generally not subject to price regulation. Work and services includes mutual assistance to other utilities, highway relocation, rentals of pole attachments, late payment fees and collection fees.

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.

Table of Contents

The changes in ACE s operating revenue net of purchased power expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Weather	$ 2	$ (7)
Volume	12	4
Distribution rate increase	4	4
Regulatory required programs	(1)	(10)
Transmission revenues	11	19
Other		1
Total increase	$ 28	$ 11

Weather. The demand for electricity is affected by weather conditions. With respect to the electric business, very warm weather in summer months and very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity. Conversely, mild weather reduces demand. During the three months ended September 30, 2016 compared to the same period in 2015, operating revenue net of purchased power and fuel expense was higher due to the impact of favorable summer weather conditions in ACE s service territory. During the nine months ended September 30, 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 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.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in ACE s service territory. The changes in heating and cooling degree days in ACE s service territory for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

				% Change	
Three Months Ended September 30,	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	17		44	%	(61.4)%
Cooling Degree-Days	1,006	883	786	13.9%	28.0%
Nine Months Ended September 30,					
Heating Degree-Days	2,938	3,524	3,143	(16.6)%	(6.5)%
Cooling Degree-Days	1,267	1,249	1,072	1.4%	18.2%

Volume. The increase in operating revenue net of purchased power expense related to delivery volume, exclusive of the effects of weather, for the three and nine months ended September 30, 2016 compared to the same periods in 2015, primarily reflects the impact of higher average customer usage.

Distribution Rate Increase. The increase in operating revenue net of purchased power expense for the three and nine months ended September 30, 2016, compared to the same periods in 2015, was primarily due to the impact of the new electric distribution base rate charged to customers that became effective in August 2016 in accordance with the NJBPU approved electric rate case order. 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 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. 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 adjustments. The increase in revenue net of purchased power expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 is a result of higher rates effective June 1, 2015 related to increases in transmission plant investment and operating expenses and due to the establishment of a reserve recorded in September 2015 related to the FERC ROE challenges.

Operating and Maintenance Expense

	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Increase (Decrease)	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	Increase (Decrease)
Operating and maintenance expense baseline	$ 66	$ 69	$ (3)	$ 343	$ 204	$ 139
Operating and maintenance expense regulatory required programs[(a)]	1	1		3	3	
Total operating and maintenance expense	$ 67	$ 70	$ (3)	$ 346	$ 207	$ 139

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in operating and maintenance expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ 3	$ 7
Storm-related costs		1
BSC and PHISCO allocations[(a)]	2	18
Uncollectible accounts expense	1	2
Merger commitments[(b)]	(10)	111
Other	1	
Total (decrease) increase	$ (3)	$ 139

(a) Primarily related to merger severance and compensation costs.

(b) Primarily related to merger-related commitments for customer rate credits, inclusive of the estimate of merger commitment costs associated with the most favored nation provision of the merger orders, and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for the three and nine months ended September 30, 2016 compared to the same periods in 2015 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)		Nine Months Ended September 30, Increase (Decrease)	
Depreciation expense[(a)]	$	1	$	4
Regulatory asset amortization[(b)]		(1)		(9)
Total decrease	$		$	(5)

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the three and nine months ended September 30, 2016 compared to the same periods 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 and nine months ended September 30, 2016 compared to the same periods in 2015, remained relatively constant.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2016 compared to the same periods in 2015 remained relatively constant.

Other, Net

Other, net for the three and nine months ended September 30, 2016 compared to the same periods in 2015 increased primarily due to higher income from AFUDC equity.

Effective Income Tax Rate

ACE s effective income tax rate was 32.9% and 38.9% for the three months ended September 30, 2016 and 2015 respectively. ACE s effective income tax rate was 13.8% and 38.3% for the nine months ended September 30, 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 $21 million during the nine months ended September 30, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

Table of Contents

ACE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	1,575	1,420	10.9%	5.6%	3,327	3,452	(3.6)%	1.6%
Small commercial & industrial	426	385	10.6%	3.1%	998	996	0.2%	0.9%
Large commercial & industrial	1,032	933	10.6%	4.0%	2,705	2,669	1.3%	1.2%
Public authorities & electric railroads	11	9	22.2%	%	35	32	9.4%	%
Total retail deliveries	3,044	2,747	10.8%	4.7%	7,065	7,149	(1.2)%	1.3%

Number of Electric Customers	As of September 30, 2016	As of September 30, 2015
Residential	483,542	482,348
Small commercial & industrial	63,826	63,671
Large commercial & industrial	845	893
Public authorities & electric railroads	593	564
Total	548,806	547,476

Electric Revenue	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	% Change	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015	% Change
Retail Sales[(a)]						
Residential	$ 249	$ 227	9.7%	$ 530	$ 549	(3.5)%
Small commercial & industrial	55	53	3.8%	133	135	(1.5)%
Large commercial & industrial	57	56	1.8%	158	155	1.9%
Public authorities & electric railroads	4	3	33.3%	10	9	11.1%
Total retail	365	339	7.7%	831	848	(2.0)%
Other revenue[(b)]	56	47	19.1%	151	155	(2.6)%
Total electric revenue[(c)]	$ 421	$ 386	9.1%	$ 982	$ 1,003	(2.1)%

(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.
(c) Includes operating revenues from affiliates totaling $1 million and $1 million for the three months ended September 30, 2016 and 2015, respectively, and $3 million and $2 million for the nine months ended September 30, 2016 and 2015, respectively.

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 September 30, 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 nine months ended September 30, 2016 and 2015. All results included throughout the liquidity 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 access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $525 million in bilateral credit facilities with banks which have various expirations dates between December 2016 and May 2021. The Registrants utilize their credit facilities to support their commercial paper programs, and provide for other short-term borrowings 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.

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, natural 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.

Table of Contents

The following table provides a summary of the major items affecting Exelon s cash flows from operations for the nine months ended September 30, 2016 and 2015:

	Nine Months Ended September 30,		
	2016[c]	2015	Variance
Net income	$ 956	$ 1,959	$ (1,003)
Add (subtract):			
Non-cash operating activities[a]	5,946	3,900	2,046
Pension and non-pension postretirement benefit contributions	(283)	(430)	147
Income taxes	527	300	227
Changes in working capital and other noncurrent assets and liabilities[b]	(516)	(197)	(319)
Option premiums (paid) received, net	(24)	27	(51)
Counterparty collateral received, net	757	115	642
Net cash flows provided by operations	$ 7,363	$ 5,674	$ 1,689

(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 September 30, 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 order to appeal the Tax Court s like-kind exchange decision, Exelon is required to pay the tax, penalty and interest at the time Exelon files its appeal (expected early 2017). While the final calculation of tax, penalties and interest has not yet been finalized by the IRS, Exelon estimates that a payment of approximately $1.4 billion related to the like-kind exchange will be due, including $300 million from ComEd, in the first quarter of 2017. While Exelon will receive a tax benefit of

Table of Contents

approximately $400 million associated with the deduction for the interest, Exelon currently has a net operating loss carryforward and thus does not expect to realize the cash benefit until 2018. Exelon s total estimated cash outflow for the like-kind exchange is $1.0 billion, of which approximately $300 million would be attributable to ComEd after giving consideration to Exelon s agreement to hold ComEd harmless from any unfavorable impacts of the after-tax interest and penalty amounts on ComEd s equity. ComEd will fund the $300 million with a combination of debt and equity in a manner to maintain its current capital structure. Upon a final appellate decision, which could take up to several years, Exelon expects to receive $80 million related to final interest computations.

Of the above amounts payable, Exelon deposited with the IRS approximately $1.25 billion in October of 2016. The remaining amount will be paid in early 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings.

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 nine months ended September 30, 2016 and 2015 by Registrant were as follows:

	Nine Months Ended September 30,	
	2016	**2015**
Exelon	$ 7,363	$ 5,674
Generation	3,723	3,206
ComEd	1,749	1,346
PECO	582	567
BGE	660	696
Pepco	504	213
DPL	267	188
ACE	315	178

	Successor		*Predecessor*
	March 24, 2016 to September 30, 2016	**January 1, 2016 to March 23, 2016**	**Nine Months Ended September 30, 2015**
PHI	$ 546	$ 264	$ 601

Changes in the Registrants cash flows from operations were generally consistent with changes in each Registrant s respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the nine months ended September 30, 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 nine months ended September 30, 2016 and 2015, Generation had net collections of counterparty cash collateral of $759 million and $186 million, respectively, primarily due to market conditions that resulted in changes to Generation s net mark-to-market position.

Table of Contents

During the nine months ended September 30, 2016 and 2015, Generation had net (payments)/collections of approximately $(24) million and $27 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

During nine months ended September 30, 2016 and 2015, ComEd posted approximately $2 million and $41 million of cash collateral to PJM, respectively. ComEd s collateral posted with PJM has decreased year over year due to lower PJM billings. As of September 30, 2016 and 2015, ComEd had approximately $33 million and $41 million cash collateral posted with PJM, respectively.

PHI, Pepco, DPL and ACE

During the nine months ended September 30, 2016, Pepco, DPL and ACE received tax refund allocations from PHI in connection with the Global Tax Settlement of $147 million, $56 million and $167 million, respectively. See Note 11 Income Taxes of the PHI 2015 Form 10-K for additional information.

Cash Flows from Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2016 and 2015 by Registrant were as follows:

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon	$ (13,219)	$ (5,689)
Generation	(3,278)	(3,020)
ComEd	(1,919)	(1,646)
PECO	(438)	(425)
BGE	(614)	(491)
Pepco	(435)	(357)
DPL	(254)	(240)
ACE	(227)	(216)

	Successor	*Predecessor*	
	March 24, 2016 to September 30, 2016	**January 1, 2016 to March 23, 2016**	**Nine Months Ended September 30, 2015**
PHI	$ (631)	$ (343)	$ (835)

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 $108 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.

Table of Contents

Capital expenditures by Registrant for the nine months ended September 30, 2016 and 2015 and projected amounts for the full year 2016 are as follows:

	Projected Full Year 2016[(a)]	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon	$ 8,821	$ 6,368	$ 5,443
Generation	3,375	2,651	2,774
ComEd[(b)]	2,625	1,950	1,670
PECO	650	448	435
BGE	850	611	506
Pepco[(c)]	500	392	374
DPL[(c)]	275	260	246
ACE[(c)]	275	227	212
Other[(d)]	100	84	58

		Successor	*Predecessor*	
	Projected Full Year 2016[(a)(c)]	March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015
PHI	$ 1,050	$ 624	$ 273	$ 855

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) 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.
(c) Projected capital expenditures reflect projections after March 23, 2016.
(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 32% and 38% of the projected 2016 capital expenditures at Generation are for the acquisition of nuclear fuel and growth (primarily new plant construction and distributed generation), 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 88%, 97%, 100%, 100%, 100% and 100% 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, include capital expenditures related to their respective smart meter programs.

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

Table of Contents

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.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the nine months ended September 30, 2016 and 2015 by Registrant were as follows:

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon	$ 1,251	$ 5,402
Generation	(501)	(421)
ComEd	147	285
PECO	77	(140)
BGE	286	(242)
Pepco	28	148
DPL	(14)	53
ACE	74	40

	Successor		*Predecessor*
	March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015
PHI	$ 65	$ 372	$ 491

Debt

See Note 10 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants debt issuances.

Dividends

Cash dividend payments and distributions during the nine months ended September 30, 2016 and 2015 by Registrant were as follows:

	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Exelon	$ 873	$ 819
Generation	167	2,368
ComEd	275	226
PECO	208	209
BGE[(a)]	142	126

Pepco	92	91
DPL	39	80
ACE	24	12

Table of Contents

	Successor	Predecessor	
	March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015
PHI	$ 174	$	$ 206

(a) Includes dividends paid on BGE s preference stock.

Quarterly dividends declared by the Exelon Board of Directors during the nine months ended September 30, 2016 and for the third quarter of 2016 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
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
Third Quarter 2016	July 26, 2016	August 15, 2016	September 9, 2016	$ 0.318
Fourth Quarter 2016	October 25, 2016	November 15, 2016	December 9, 2016	$ 0.318

(a) Exelon s Board of Directors approved a revised dividend policy. The approved policy will raise the dividend 2.5% each year for the next three years, beginning with the June 2016 dividend and subject to Board approval.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during the nine months ended September 30, 2016 and 2015 by Registrant were as follows:

	Nine months ended September 30, 2016	2015
Exelon	$ (1,014)	$ 230
Generation	43	
ComEd	(284)	300
BGE	(210)	(70)
Pepco	(64)	(56)
DPL	(88)	(40)
ACE	(5)	98

	Successor	Predecessor	
	March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015
PHI	$ (820)	$ 379	$ 399

Contributions from Parent/Member

Contributions received from Parent/Member for the nine months ended September 30, 2016 and 2015 by Registrant were as follows:

Nine months ended September 30,

	2016	2015
Generation	$ 142	$ 55
ComEd	188[(a)]	75[(a)]
PECO	18	16
BGE	28[(a)]	6
Pepco	187[(b)]	112[(b)]
DPL	113[(b)]	75[(b)]
ACE	139[(b)]	

	Successor	Predecessor	
	March 24, 2016 to September 30, 2016	January 1, 2016 to March 23, 2016	Nine Months Ended September 30, 2015
PHI	$ 1,088[(a)]	$	$

(a) Contribution paid by Exelon.
(b) Contribution paid by PHI.

Pursuant to the orders approving the merger, Exelon made 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.

Redemptions of Preference Stock

On July 3, 2016, BGE redeemed all 400,000 shares of its outstanding 7.125% Cumulative Preference Stock, 1993 Series and all 600,000 shares of its outstanding 6.99% Cumulative Preference Stock, 1995 Series for $100 million, plus accrued and unpaid dividends. On September 18, 2016, BGE redeemed all remaining 500,000 shares of its outstanding 6.97% Cumulative Preference Stock, 1993 Series and all 400,000 shares of its outstanding 6.70% Cumulative Preference Stock, 1995 Series for $90 million, plus accrued and unpaid dividends. See Note 17 Earnings Per Share and Equity of the Combined Notes to Consolidated Financial Statements for further details.

Other

For the nine months ended September 30, 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.

Credit Matters

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include $9.5 billion in aggregate total commitments of which $7.9 billion was available as of September 30, 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 third 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 September 30, 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.

Table of Contents

The following table presents the incremental collateral that each utility registrant would have been required to provide in the event each utility registrant lost its investment grade credit rating at September 30, 2016 and available credit facility capacity prior to any incremental collateral at September 30, 2016:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 17	$	$ 998
PECO	3	25	598
BGE	2	29	600
Pepco			300
DPL	3	9	300
ACE			299

(a) Represents incremental collateral related to natural gas procurement contracts.

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 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.

The following table reflects the Registrants commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at September 30, 2016:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size[(a)(b)]	Outstanding Commercial Paper at September 30, 2016	Average Interest Rate on Commercial Paper Borrowings for the Nine Months Ended September 30, 2016
Exelon Corporate	$ 600	$	0.70%
Generation	5,300		1.01%
ComEd	1,000	10	0.77%
PECO	600		%
BGE	600		0.77%
Pepco	500		0.67%
DPL	500	17	0.69%
ACE	350		0.65%

(a) Excludes $525 million bilateral credit facilities that do not back Generation s commercial paper program.

(b) Excludes additional credit facility agreements for Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $50 million, $34 million, $34 million, $5 million, $2 million, $2 million and $2 million, respectively, arranged with minority and community banks located primarily within utilities service territories. These facilities expire on October 13, 2017. These facilities are solely utilized to issue letters of credit. As of September 30, 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.

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

Table of Contents

capacity under its credit facility. At September 30, 2016, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

Credit Agreements

					Available Capacity at September 30, 2016	
		Aggregate		Outstanding		To Support Additional
Borrower	**Facility Type**	**Bank Commitment[a][b][c]**	**Facility Draws**	**Letters of Credit**	**Actual**	**Commercial Paper[d]**
Exelon Corporate	Syndicated Revolver	$ 600	$	$ 29	$ 571	$ 571
Generation[e]	Syndicated Revolver	5,300		1,264	4,036	4,036
Generation	Bilaterals	525	40	319	166	
ComEd	Syndicated Revolver	1,000		2	998	988
PECO	Syndicated Revolver	600		2	598	598
BGE	Syndicated Revolver	600			600	600
Pepco	Syndicated Revolver	300			300	300
DPL	Syndicated Revolver	300			300	283
ACE	Syndicated Revolver	300		1	299	299

(a) Excludes $129 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. These facilities expire on October 13, 2017. These facilities are solely utilized to issue letters of credit. As of September 30, 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.

(b) Pepco, DPL and ACE s revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility

(c) Excludes nonrecourse debt letters of credit, see Note 14 Debt and Credit Agreements in the Exelon 2015 Form 10-K for further information on Continental Wind nonrecourse debt.

(d) Excludes $525 million bilateral credit facilities that do not back Generation s commercial paper program.

(e) Excludes ExGen Texas Power Financing s $4 million of borrowed debt on its revolving credit facility.

As of September 30, 2016, there was $40 million of borrowings under Generation s bilateral credit facilities.

Borrowings under Exelon Corporate s, Generation s, ComEd s, PECO s, BGE s, Pepco s, DPL s, and ACE s revolving credit agreements bear intere at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant s credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	**Generation**	**ComEd**	**PECO**	**BGE**	**Pepco**	**DPL**	**ACE**
Prime based borrowings	27.5	27.5	7.5	0.0	0.0	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the nine months ended September 30, 2016:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At September 30, 2016, the interest coverage ratios at Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	7.25	11.67	7.60	9.16	10.76	6.19	8.26	5.60

An event of default under Exelon, Generation, ComEd, PECO or BGE s indebtedness will not constitute an event of default under any of the others credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE s indebtedness will not constitute an event of default 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 $50 million in the aggregate will constitute an event of default under the credit facility.

The absence of a material adverse change in Exelon s or PHI s business, property, results of operations or financial condition is not a condition to the availability of credit under 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 September 30, 2016, are presented in the following table:

Exelon Intercompany Money Pool	**During the Three Months Ended September 30, 2016**		**As of September 30, 2016**
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 1,138	n/a	$ 708
Generation		(1,007)	(461)
PECO	210		
BSC		(378)	(303)
PHI Corporate[(a)]	n/a	(53)	(7)
PCI[(a)]	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.

PHI Intercompany Money Pool	During the Three Months Ended September 30, 2016		As of September 30, 2016
	Maximum	Maximum	
Contributed (borrowed)	Contributed	Borrowed	Contributed (Borrowed)
PHI Corporate	$ 44	n/a	$
Pepco			
DPL			
ACE			
PHISCO	26	(44)	

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, BGE, Pepco and DPL have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

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[(a)]			Long-term Financing Authority		
	Commission	Expiration Date	Amount (in millions)	Commission	Expiration Date	Amount (in millions)
ComEd[(b)]	FERC	December 31, 2017	$2,500	ICC	2019	$2,383
PECO	FERC	December 31, 2017	1,500	PAPUC	December 31, 2018	1,600
BGE	FERC	December 31, 2017	700	MDPSC	N/A	
Pepco	FERC	June 30, 2018	500	MDPSC / DCPSC	September 25, 2017	550
DPL	FERC	June 30, 2018	500	MDPSC / DPSC	December 31, 2017	300
ACE	NJPU	January 1, 2018	350	NJBPU	December 31, 2017	300

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.
(b) ComEd had $1,565 million available in long-term debt refinancing authority and $818 million available in new money long term debt financing authority from the ICC as of September 30, 2016 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.

286

Table of Contents

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.

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 September 30, 2016, the proportion of expected generation hedged is 98%-101%, 85%-88% and 54%-57% for 2016, 2017 and 2018, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales to the Utility Registrants to serve their retail load.

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 September 30, 2016 market conditions and hedged position would be an increase in pre-tax net income of approximately $5 million for 2016 and decreases of approximately $125 million and $415 million, respectively, for 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.

Table of Contents

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 1,506 GWhs and 4,015 GWhs for the three and nine months ended September 30, 2016, respectively, and 1,913 GWhs and 5,378 GWhs for the three and nine months ended September 30, 2015, respectively, are a complement to Generation s energy marketing portfolio, but represent a small portion of Generation s overall revenue from energy marketing activities. Proprietary trading portfolio activity for the nine months ended September 30, 2016 resulted in pre-tax gains of $9 million due to net mark-to-market gains of $1 million and $8 million 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 nine months ended September 30, 2016 of $6,754 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 57% 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

Table of Contents

contracts which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. 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.

DPL

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 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).

Table of Contents

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 September 30, 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 September 30, 2016 and December 31, 2015.

	Generation	ComEd	DPL[(a)]	Exelon[(b)]
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015[(c)]	$ 1,753	$ (247)	$	$ 1,506
Total change in fair value during 2016 of contracts recorded in results of operations	181			181
Reclassification to realized at settlement of contracts recorded in results of operations	(284)			(284)
Contracts received at acquisition date[(f)]	(59)			(59)
Changes in fair value recorded through regulatory assets and liabilities[(d)]		3	3	3
Changes in allocated collateral	(749)		(3)	(749)
Changes in net option premium paid/(received)	24			24
Option premium amortization	20			20
Upfront payments and amortizations[(e)]	102			102
Total mark-to-market energy contract net assets (liabilities) at September 30, 2016[(c)]	$ 988	$ (244)	$	$ 744

(a) As of September 30, 2016 and December 31, 2015, PHI s and DPL s mark-to-market derivative asset 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 decrease 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 September 30, 2016. For the successor period of March 24, 2016 to September 30, 2016, there was a $2 million increase in fair value and $2 million decrease in 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 September 30, 2016, ComEd recorded a $244 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the nine months ended September 30, 2016, ComEd also recorded $10 million of decreases in fair value and realized losses due to settlements of $13 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers. As of September 30, 2016, DPL recorded a $1 million regulatory liability related to its mark-to-market derivative liabilities.

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

(f) Includes fair value from contracts received at acquisition of ConEdison Solutions of $(59) million.

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						
	2016	2017	2018	2019	2020	2021 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ (9)	$ 26	$ (35)	$ (38)	$ (13)	$ 1	$ (68)
Prices provided by external sources (Level 2)	39	115	3	(34)	(2)		121
Prices based on model or other valuation methods (Level 3)[c]	70	435	202	64	12	(92)	691
Total	$ 100	$ 576	$ 170	$ (8)	$ (3)	$ (91)	$ 744

(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 $485 million at September 30, 2016.
(c) Includes ComEd s net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2016	2017	2018	2019	2020	2021 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[a][b]:							
Actively quoted prices (Level 1)	$ (9)	$ 26	$ (35)	$ (38)	$ (13)	$ 1	$ (68)
Prices provided by external sources (Level 2)	39	115	3	(34)	(2)		121
Prices based on model or other valuation methods (Level 3)	77	454	221	83	31	69	935
Total	$ 107	$ 595	$ 189	$ 11	$ 16	$ 70	$ 988

(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 $485 million at September 30, 2016.

ComEd

	Maturities Within						
	2016	2017	2018	2019	2020	2021 and Beyond	Total Fair Value
Commodity derivative contracts[a]:							
Prices based on model or other valuation methods (Level 3)	$ (7)	$ (19)	$ (19)	$ (19)	$ (19)	$ (161)	$ (244)

(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.

Table of Contents

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 September 30, 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 $24 million, $45 million, $22 million, $47 million, $12 million, and $10 million as of September 30, 2016, respectively.

Rating as of September 30, 2016	Total Exposure Before Credit Collateral	Credit Collateral[(a)]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,017	$ 4	$ 1,013	1	$ 355
Non-investment grade	175	22	153		
No external ratings					
Internally rated investment grade	423	3	420		
Internally rated non-investment grade	61	3	58		
Total	$ 1,676	$ 32	$ 1,644	1	$ 355

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2016	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 769	$ 242	$ 6	$ 1,017
Non-investment grade	122	53		175
No external ratings				
Internally rated investment grade	353	47	23	423
Internally rated non-investment grade	43	18		61
Total	$ 1,287	$ 360	$ 29	$ 1,676

Net Credit Exposure by Type of Counterparty	As of September 30, 2016
Financial institutions	$ 117
Investor-owned utilities, marketers, power producers	757
Energy cooperatives and municipalities	712
Other	58
Total	$ 1,644

(a) As of September 30, 2016, credit collateral held from counterparties where Generation had credit exposure included $10 million of cash and $22 million of letters of credit. The credit collateral does not include non-liquid collateral.

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.

As of September 30, 2016, Generation had cash collateral of $501 million posted and cash collateral held of $18 million for external counterparties with derivative positions, of which $485 million and $3 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 September 30, 2016, $5 million of cash collateral held 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 September 30, 2016, ComEd held $3 million in 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 September 30, 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 September 30, 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 September 30, 2016, DPL was not required to post collateral 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 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 September 30, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Generation had $672 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 $5 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 2016. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

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 September 30, 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 $535 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of equity price risk as a result of the current capital and credit market conditions.

Item 4. Controls and Procedures

During the third 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, includ its principal executive officer and principal financial officer, evaluated its disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by all Registrants to ensure that (a) material information relating to that Registrant, including its consolidated subsidiaries, is accumulated and made known to Exelon s management, including its principal executive officer and principal financial officer, by other employees of that Registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of September 30, 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. Exelon is currently in the process of integrating PHI s operations, processes and internal controls. There have been no changes in internal control over financial reporting that occurred during the third 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 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.

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 recent Tax Court decision on Exelon s like-kind exchange position, Exelon and ComEd have revised the description of their risk related to the 1999 sale of ComEd s fossil generating assets. In addition, due to the close of the PHI merger on March 23, 2016, Exelon is subject to additional risks related to the merger as described below.

Market and Financial Factors

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants results of operations or cash flows. (Exelon, Generation, ComEd, PECO and BGE)

1999 sale of fossil generating assets. On September 19, 2016, the Tax Court rejected Exelon s like-kind exchange position and ruled that Exelon was not entitled to defer gain on the transaction. In addition, contrary to Exelon s evaluation that the penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and after-tax interest due on the asserted penalty. In early 2017, Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit.

In order to appeal the Tax Court s like-kind exchange decision, Exelon is required to pay the tax, penalty and interest for the tax years before the Court at the time Exelon files its appeal (expected early 2017). Exelon deposited with the IRS approximately $1,250 million in October 2016. The total amount of tax, penalty and interest payable is currently being computed pursuant to the Tax Court rules. Any remaining amounts due, which are not expected to be materially different from the amount deposited, will be paid in early 2017 at the time Exelon files its appeal of the Tax Court decision. If Exelon s deposit exceeds the final Tax Court computation, Exelon can request a return of the excess.

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.

Table of Contents

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.

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.

Table of Contents

Item 6. Exhibits

Certain of the following exhibits are incorporated herein by reference under Rule 12b-32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
4.1	Form of 2.400% notes due 2026 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.1)
4.2	Form of 3.500% notes due 2046 (File No. 001-01910, Form 8-K dated August 18, 2016, Exhibit 4.2)
4.3	One Hundred and Thirteenth Supplemental Indenture dated as of September 1, 2016 from PECO to U.S. Bank National Association, as trustee (File No. 000-16844, Form 8-K dated September 21, 2016, Exhibit 4.1)
10.1	2016 Form of Exelon Corporation Change in Control Agreement
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 September 30, 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

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended September 30, 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

Table of Contents

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)	

October 26, 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)	

October 26, 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 President and Chief Executive Officer (Principal Executive Officer)	/s/ JOSEPH R. TRPIK, JR. Joseph R. Trpik, Jr. Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)

/s/ Gerald J. Kozel
Gerald J. Kozel
Vice President and Controller

(Principal Accounting Officer)
October 26, 2016

Table of Contents

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/ Phillip S. Barnett
Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

/s/ Scott A. Bailey
Scott A. Bailey
Vice President and Controller

(Principal Accounting Officer)

October 26, 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/ David M. Vahos
David M. Vahos
Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

/s/ Andrew W. Holmes
Andrew W. Holmes
Vice President and Controller

(Principal Accounting Officer)

October 26, 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
President and Chief Executive Officer

(Principal Executive Officer)

/s/ Donna J. Kinzel
Donna J. Kinzel
Senior Vice President, Chief Financial Officer and Treasurer

(Principal Financial Officer)

/s/ Robert M. Aiken

Robert M. Aiken
Vice President and Controller

(Principal Accounting Officer)
October 26, 2016

Table of Contents

Pursuant to requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

POTOMAC ELECTRIC POWER COMPANY

/s/ DAVID M. VELAZQUEZ	/s/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken	
Vice President and Controller	
(Principal Accounting Officer)	

October 26, 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	/s/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken	
Vice President and Controller	
(Principal Accounting Officer)	

October 26, 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	/s/ DONNA J. KINZEL
David M. Velazquez	Donna J. Kinzel
President and Chief Executive Officer	Senior Vice President, Chief Financial Officer and Treasurer
(Principal Executive Officer)	(Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken	
Vice President and Controller	
(Principal Accounting Officer)	

October 26, 2016