ATLANTIC CITY ELECTRIC CO
Form 10-K
February 13, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 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)**	36-0938600

	440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	
000-16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY** **(a Maryland corporation)** 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210
001-31403	**PEPCO HOLDINGS LLC** **(a Delaware limited liability company)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	52-2297449
001-01072	**POTOMAC ELECTRIC POWER COMPANY** **(a District of Columbia and Virginia corporation)** 701 Ninth Street, N.W. Washington, District of Columbia 20068 (202) 872-2000	53-0127880
001-01405	**DELMARVA POWER & LIGHT COMPANY** **(a Delaware and Virginia corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	51-0084283
001-03559	**ATLANTIC CITY ELECTRIC COMPANY** **(a New Jersey corporation)** 500 North Wakefield Drive Newark, Delaware 19702 (202) 872-2000	21-0398280

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Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
Series A Junior Subordinated Debentures	New York
Corporate Units	New York
PECO ENERGY COMPANY:	
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York
BALTIMORE GAS AND ELECTRIC COMPANY:	
6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

Securities registered pursuant to Section 12(g) of the Act:

Title of Each Class

COMMONWEALTH EDISON COMPANY:

Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

POTOMAC ELECTRIC POWER COMPANY:

Common Stock, $.01 par value

DELMARVA POWER & LIGHT COMPANY:

Common Stock, $2.25 par value

ATLANTIC CITY ELECTRIC COMPANY:

Common Stock, $3.00 par value

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes	No
Exelon Generation Company, LLC	Yes	No
Commonwealth Edison Company	Yes	No
PECO Energy Company	Yes	No
Baltimore Gas and Electric Company	Yes	No
Pepco Holdings LLC	Yes	No
Potomac Electric Power Company	Yes	No
Delmarva Power & Light Company	Yes	No
Atlantic City Electric Company	Yes	No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Exelon Corporation	Yes	No
Exelon Generation Company, LLC	Yes	No
Commonwealth Edison Company	Yes	No
PECO Energy Company	Yes	No
Baltimore Gas and Electric Company	Yes	No
Pepco Holdings LLC	Yes	No
Potomac Electric Power Company	Yes	No
Delmarva Power & Light Company	Yes	No
Atlantic City Electric Company	Yes	No

Indicate by check mark whether the registrants (1) have 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) have been subject to such filing requirements for the past 90 days. Yes No

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2016 was as follows:

Exelon Corporation Common Stock, without par value	$33,527,039,724
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None
Baltimore Gas and Electric Company, without par value	None
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company	None
Delmarva Power & Light Company	None
Atlantic City Electric Company	None

The number of shares outstanding of each registrant s common stock as of January 31, 2017 was as follows:

Exelon Corporation Common Stock, without par value	926,589,614
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,017,157
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, 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

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2017 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2017 Information Statement are

incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company, Baltimore Gas and Electric Company, Pepco Holdings LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form in the reduced disclosure format.

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PART III

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PCI	Potomac Capital Investment Corporation and its subsidiaries
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
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
EGTP	ExGen Texas Power, LLC
EGR	ExGen Renewables I, LLC
AmerGen	AmerGen Energy Company, LLC
RPG	Renewable Power Generation
SolGen	SolGen, 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
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
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
UII	Unicom Investments, Inc.

Other Terms and Abbreviations

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

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Other Terms and Abbreviations

AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
AOCI	Accumulated Other Comprehensive Income
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
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
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

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Other Terms and Abbreviations

DPSC	Delaware Public Service Commission
DRP	Direct Stock Purchase and Dividend Reinvestment Plan
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDCs	Electric distribution companies
EDF	Electricite de France SA and its subsidiaries
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower Maryland	A Maryland demand-side management program for Pepco and DPL
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
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
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

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Other Terms and Abbreviations

LLRW	Low-Level Radioactive Waste
LT Plan	Long-term renewable resources procurement plan
LTIP	Long-Term Incentive Plan
MAPP	Mid-Atlantic Power Pathway
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
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

Other Terms and Abbreviations

PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units or portions thereof whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
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 and oil exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council
ZEC	Zero Emission Credit
ZES	Zero Emission Standard

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FILING FORMAT

This combined Annual Report on Form 10-K 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 a Registrants include those factors discussed herein, including those factors discussed with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 24; and (d) 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.

PART I

ITEM 1. BUSINESS
General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO, BGE, PHI, Pepco, DPL and ACE in the energy delivery businesses discussed below. Exelon s principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 800-483-3220.

Generation

Generation s integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

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Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO.

Generation s principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

ComEd s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in northern Illinois, including the City of Chicago.

ComEd was organized in the State of Illinois in 1913 as a result of the merger of Cosmopolitan Electric Company into the original corporation named Commonwealth Edison Company, which was incorporated in 1907. ComEd s principal executive offices are located at 440 South LaSalle Street, Chicago, Illinois 60605, and its telephone number is 312-394-4321.

PECO

PECO s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia.

PECO was incorporated in Pennsylvania in 1929. PECO s principal executive offices are located at 2301 Market Street, Philadelphia, Pennsylvania 19103, and its telephone number is 215-841-4000.

BGE

BGE s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in central Maryland, including the City of Baltimore.

BGE was incorporated in Maryland in 1906. BGE s principal executive offices are located at 110 West Fayette Street, Baltimore, Maryland 21201, and its telephone number is 410-234-5000.

PHI

PHI is a utility services holding company engaged, through its reportable segments Pepco, DPL and ACE, in the energy delivery businesses discussed below. On March 23, 2016, Pepco Holdings, Inc., converted from a Delaware corporation to a Delaware limited liability company, Pepco Holdings LLC. PHI s principal executive offices are located at 701 Ninth Street, N.W., Washington, D.C. 20068, and its telephone number is 202-872-2000.

Pepco

Pepco s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in the District of Columbia and major portions of

Montgomery County and Prince George s County in Maryland.

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Pepco was incorporated in the District of Columbia in 1896 and Virginia in 1949. Pepco s principal executive offices are located at 701 Ninth Street, N.W., Washington, D.C. 20068, and its telephone number is 202-872-2000.

DPL

DPL s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in portions of Delaware and Maryland, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in portions of New Castle County in Delaware.

DPL was incorporated in Delaware in 1909 and Virginia in 1979. DPL s principal executive offices are located at 500 North Wakefield Drive, Newark, Delaware 19702, and its telephone number is 202-872-2000.

ACE

ACE s energy delivery business consists of the purchase and regulated retail sale of electricity and the provision of electricity transmission and distribution services to retail customers in portions of southern New Jersey.

ACE was incorporated in New Jersey in 1924. ACE s principal executive offices are located at 500 North Wakefield Drive, Newark, Delaware 19702, and its telephone number is 202-872-2000.

Business Services

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.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Operating Segments

See Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s operating segments.

Merger with Pepco Holdings, Inc. (Exelon)

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

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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. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the PHI transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. Constellation sells electricity and natural gas, including renewable energy, in competitive energy markets to both wholesale and retail customers. The retail sales include commercial, industrial and residential customers. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Generation s fleet also provides geographic and supply source diversity. Generation s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation s customer facing activities foster development and delivery of other innovative energy-related products and services for its customers.

Generation is a public utility under the Federal Power Act and is subject to FERC s exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC s jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. PJM, MISO, ISO-NE and SPP, have been approved by FERC as RTOs, and CAISO and ISO-NY have been approved as ISOs. These entities are responsible for regional planning, managing transmission congestion, developing wholesale markets for energy and capacity, maintaining reliability, market monitoring, the scheduling of physical power sales brokered through ICE and NYMEX and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Constellation Energy Nuclear Group, Inc.

Generation owns a 50.01% interest in CENG, a joint venture with EDF. CENG is governed by a board of ten directors, five of which are appointed by Generation and five by EDF. CENG owns a total of five nuclear generating facilities on three sites, Calvert Cliffs, R.E. Ginna and Nine Mile Point. CENG s ownership share in the total capacity of these units is 4,007 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF s noncontrolling interests in CENG at fair value on a fully consolidated basis in Exelon s and Generation s Consolidated Balance Sheets. Refer to Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for further information regarding the integration transaction.

Acquisitions

ConEdison Solutions. On September 1, 2016, Generation acquired the competitive retail electric and natural gas business activities of 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 were excluded from the transaction.

Integrys Energy Services, Inc. On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of $332 million, including net working capital. The generation and solar asset businesses of Integrys were excluded from the transaction.

Merger with Constellation Energy Group, Inc. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger. Since the merger transaction, Generation includes the former Constellation generation and customer supply operations.

Dispositions

Upstream Disposition. On June 16, 2016, Generation initiated the sales process of its Upstream business. See Note 14 Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain(loss) on sales of assets on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016.

Asset Divestitures. During 2014 and 2015, Generation sold certain generating assets with total pre-tax proceeds of $1.8 billion (after-tax proceeds of approximately $1.4 billion). Proceeds were used primarily to finance a portion of the acquisition of PHI.

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Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger with Constellation Energy Group, Inc. for net proceeds of approximately $371 million, which resulted in a pre-tax impairment charge of $272 million.

See Note 4 Mergers, Acquisitions, and Dispositions and Note 8 Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2016, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [(a)(b)]	
Nuclear	19,457
Fossil (primarily natural gas and oil)	9,548
Renewable [(c)]	3,715
Owned generation assets	32,720
Long-term power purchase contracts [(d)]	6,879
Total generating resources	39,599

(a) See Fuel for sources of fuels used in electric generation.
(b) Net generation capacity is stated at proportionate ownership share. See ITEM 2. PROPERTIES Generation for additional information.
(c) Includes wind, hydroelectric, and solar generating assets.
(d) Electric supply procured under site specific agreements.

Generation has six reportable segments, the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions, representing the different geographical areas in which Generation s customer-facing activities are conducted and where Generation s generating resources are located.

Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 36% of capacity).

Midwest represents operations in the western half of PJM, which includes portions of Illinois, 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, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 37% of capacity).

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 7% of capacity).

New York represents the operations within ISO-NY, which covers the state of New York in its entirety (approximately 3% of capacity).

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 11% of capacity).

Other Power Regions is an aggregate of regions not considered individually significant (approximately 6% of capacity).

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See Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on revenues from external customers and revenues net of purchased power and fuel expense for each of Generation s reportable segments.

Nuclear Facilities

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,457 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership), and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon s and Generation s financial statements relative to its proportionate ownership interest in each unit. In addition, Generation owns a 50.01% interest, collectively, in the CENG generating stations (Calvert Cliffs, Nine Mile Point [excluding LIPA s 18% ownership interest in Nine Mile Point Unit 2] and R.E. Ginna) which are 100% consolidated on Exelon and Generation s financial statements as of April 1, 2014. See Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Combined Notes to Consolidated Financial Statements for additional information. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the impact of the Future Energy Jobs Bill and New York CES on certain nuclear plants.

Generation s nuclear generating stations are all operated by Generation, with the exception of the two units at Salem, which are operated by PSEG Nuclear, LLC (PSEG Nuclear), an indirect, wholly owned subsidiary of PSEG. In 2016, 2015 and 2014 electric supply (in GWh) generated from the nuclear generating facilities was 67%, 68% and 67%, respectively, of Generation s total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation s wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation s electric supply sources.

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. Closing of the transaction is currently anticipated to occur in the first half of 2017 and requires 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. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional detail on the proposed acquisition of the FitzPatrick nuclear generating station.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non-refueling outages, can have a significant impact on Generation s results of operations. As the largest generator of nuclear power in the United States, Generation can negotiate favorable terms for the materials and services that its business requires. Generation s operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2016, 2015 and 2014, the nuclear generating facilities operated by Generation achieved capacity factors of 94.6%, 93.7% and 94.3%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG as of April 1, 2014. Generation manages its scheduled refueling outages to minimize their duration and to maintain high nuclear generating capacity factors, resulting in a stable generation base for Generation s wholesale and retail

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marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

In addition to the maintenance and equipment upgrades performed by Generation during scheduled refueling outages, Generation has extensive operating and security procedures in place to ensure the safe operation of the nuclear units. Generation has extensive safety systems in place to protect the plant, personnel and surrounding area in the unlikely event of an accident or other incident.

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of January 30, 2017, the NRC categorized Ginna in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column, which is the highest performance band. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

For information on the NRC actions related to the Japan Earthquake and Tsunami and the industry s response, see ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Executive Overview.

Licenses. Generation has original 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals from the NRC for all its nuclear units except Clinton. Additionally, PSEG has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

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The following table summarizes the current operating license expiration dates for Generation s nuclear facilities in service:

Station	Unit	In-Service Date [(a)]	Current License Expiration
Braidwood	1	1988	2046
	2	1988	2047
Byron	1	1985	2044
	2	1987	2046
Calvert Cliffs	1	1975	2034
	2	1977	2036
Clinton [(b)]	1	1987	2026
Dresden	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Oyster Creek [(c)]	1	1969	2029
Peach Bottom [(d)]	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
R.E. Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040
Three Mile Island	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) Although timing has been delayed, Generation currently plans to seek license renewal for Clinton and has advised the NRC that any license renewal application would not be filed until the first quarter of 2021.
(c) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. In 2016, Exelon notified the NRC that it will cease operations at Oyster Creek on November 30, 2019.
(d) On June 7, 2016, Generation announced that it will submit a second 20 year license renewal application to NRC for Peach Bottom Units 2 and 3 in 2018.

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. The NRC review process takes approximately two years from the docketing of an application. To date, each granted license renewal has been for 20 years beyond the original operating license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual renewal of operating licenses for all of Generation s operating nuclear generating stations except for Oyster Creek and Clinton. Oyster Creek depreciation provisions are based on the 2019 expected shutdown date. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois Zero Emissions Standard. See Note

3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional detail on the new Illinois legislation and Note 9 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional detail on the reversal of the decision to early retire Clinton.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. On

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December 16, 2016, Generation was notified by OPPD of the termination of the operating services agreement for Fort Calhoun Station effective June 14, 2017. OPPD has the option to continue to use the Exelon Nuclear Management Model for payment of a fee.

Nuclear Waste Storage and Disposal. There are no facilities for the reprocessing or permanent disposal of SNF currently in operation in the United States, nor has the NRC licensed any such facilities. Generation currently stores all SNF generated by its nuclear generating facilities on-site in storage pools or in dry cask storage facilities. Since Generation s SNF storage pools generally do not have sufficient storage capacity for the life of the respective plant, Generation has developed dry cask storage facilities to support operations.

As of December 31, 2016, Generation had approximately 77,900 SNF assemblies (19,200 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Three Mile Island, where such storage is projected to be in operation in 2023. On-site dry cask storage in concert with on-site storage pools will be capable of meeting all current and future SNF storage requirements at Generation s sites through the end of the license renewal periods and through decommissioning.

For a discussion of matters associated with Generation s contracts with the DOE for the disposal of SNF, see Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

As a by-product of their operations, nuclear generating units produce LLRW. LLRW is accumulated at each generating station and permanently disposed of at licensed disposal facilities. The Federal Low-Level Radioactive Waste Policy Act of 1980 provides that states may enter into agreements to provide regional disposal facilities for LLRW and restrict use of those facilities to waste generated within the region. Illinois and Kentucky have entered into such an agreement, although neither state currently has an operational site and none is anticipated to be operational until after 2020.

Generation ships its Class A LLRW, which represents 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut.

Generation utilizes on-site storage capacity at all its stations to store and stage for shipping Class B and Class C LLRW. Generation has a contract through 2032 to ship Class B and Class C LLRW to a disposal facility in Texas. The agreement provides for disposal of all current Class B and Class C LLRW currently stored at each station as well as the Class B and Class C LLRW generated during the term of the agreement. However, because the production of LLRW from Generation s nuclear fleet will exceed the capacity at the Texas site (3.9 million curies for 15 years beginning in 2012), Generation will still be required to utilize on-site storage at its stations for Class B and Class C LLRW. Generation currently has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation s nuclear fleet. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. 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

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reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See Nuclear Insurance within Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for details.

For information regarding property insurance, see ITEM 2. PROPERTIES Generation. Generation is self-insured to the extent that any losses may exceed the amount of insurance maintained or are within the policy deductible for its insured losses. Such losses could have a material adverse effect on Exelon s and Generation s future financial conditions and results of operations and cash flows.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Note 3 Regulatory Matters, Note 12 Fair Value of Financial Assets and Liabilities and Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation s NDT funds and its decommissioning obligations. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon s and Generation s Consolidated Balance Sheets at December 31, 2016 at fair value of approximately $11.1 billion and have an estimated targeted annual pre-tax return of 5.3% to 5.9%.

Zion Station Decommissioning. On December 11, 2007, Generation entered into an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions, LLC (ZionSolutions) under which ZionSolutions assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998.

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation s transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for a discussion of variable interest entity considerations related to ZionSolutions.

Fossil and Renewable Facilities (including Hydroelectric)

At December 31, 2016, Generation had ownership interests in 13,263 MW of capacity in generating facilities currently in service, consisting of 9,522 MW of natural gas and oil, 3,715 MW of renewables (wind, hydroelectric, and solar) and 26 MW of waste coal. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Wyman; (2) certain wind project entities with minority interest owners; and (3) an ownership interest in the Albany Green Energy, LLC project entity, see Note 2 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding certain of these entities which are VIEs. Generation s fossil and renewable generating stations are all operated by Generation, with the exception of LaPorte

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and Wyman, which are operated by third parties. In 2016, 2015 and 2014, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 10%, 8% and 13%, respectively, of Generation s total electric supply. The majority of this output was dispatched to support Generation s wholesale and retail power marketing activities. For additional information regarding Generation s electric generating facilities, see ITEM 2. PROPERTIES Exelon Generation Company, LLC and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. On December 22, 2015, FERC issued a new 40-year license for Muddy Run. The license term expires on December 1, 2055. Based on the FERC procedural schedule, the FERC licensing process was not completed prior to the expiration of Conowingo s license on September 1, 2014. FERC is required to issue an annual license for the facility until the new license is issued. On September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. If FERC does not issue a new license prior to the expiration of annual license, the annual license will renew automatically. The stations are currently being depreciated over their estimated useful lives, which includes actual and anticipated license renewal periods. Refer to Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Insurance. Generation maintains business interruption insurance for its renewable and fossil projects, and delay in start-up insurance for its renewable and fossil projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations, unless required by financing agreements; see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on financing agreements. Generation maintains both property damage and liability insurance. For property damage and liability claims for these operations, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Such losses could have a material adverse effect on Exelon s and Generation s future financial conditions and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES Exelon Generation Company, LLC.

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Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation s long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2016:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	16	2017 - 2032	800
Midwest	6	2017 - 2026	1,236
New England	8	2017	650
ERCOT	5	2020 - 2031	1,501
Other Power Regions	11	2017 - 2030	2,692
Total	46		6,879

	2017	2018	2019	2020	2021
Capacity Expiring (MW)	1,790	101	644	980	815

Fuel

The following table shows sources of electric supply in GWh for 2016 and 2015:

	Source of Electric Supply	
	2016	2015
Nuclear (a)	176,799	175,474
Purchases non-trading portfolio	59,987	63,637
Fossil (primarily natural gas and oil)	19,830	14,936
Renewable (b)	6,324	5,982
Total supply	262,940	260,029

(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). Nuclear generation for 2016 and 2015 includes physical volumes of 33,444 GWh and 33,415 GWh, respectively, for CENG.

(b) Includes wind, hydroelectric, and solar generating assets.

The fuel costs per MWh for nuclear generation are less than those for fossil-fuel generation. Consequently, nuclear generation is generally the most cost-effective way for Generation to meet its wholesale and retail load servicing requirements.

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2018. Generation s contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2017. All of Generation s enrichment requirements have been contracted through 2020. Contracts for fuel fabrication have been obtained through 2022. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are

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available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

Generation s integrated business operations include the physical delivery and marketing of power obtained through its generation capacity and through long-term, intermediate-term and short-term contracts. Generation maintains an effective supply strategy through ownership of generation assets and power purchase and lease agreements. Generation has also contracted for access to additional generation through bilateral long-term PPAs. PPAs, including tolling agreements, are commitments related to power generation of specific generation plants and/or are dispatchable in nature similar to asset ownership depending on the type of underlying asset. Generation secures contracted generation as part of its overall strategic plan, with objectives such as obtaining low-cost energy supply sources to meet its physical delivery obligations to both wholesale and retail customers and assisting customers to meet renewable portfolio standards. Generation sells electricity, natural gas, and other energy related products and solutions to various customers, including distribution utilities, municipalities, cooperatives, and commercial, industrial, governmental, and residential customers in competitive markets. Generation s customer facing operations combine a unified sales force with a customer-centric model that leverages technology to broaden the range of products and solutions offered, which Generation believes promotes stronger customer relationships. This model focuses on efficiency and cost reduction, which provides a platform that is scalable and able to capitalize on opportunities for future growth.

Generation may purchase more than the energy demanded by its customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions.

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to commodity price risk in 2017 and beyond for portions of its electricity portfolio that are unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2016, the percentage of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that

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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 sales to ComEd, PECO, BGE, Pepco, DPL, and ACE to serve their retail load. A portion of Generation s hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. The corporate risk management group and Exelon s RMC monitor the financial risks of the wholesale and retail power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation s efforts. 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 limits, to manage exposure to market risk. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

Capital Expenditures

Generation s business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation s estimated capital expenditures for 2017 are as follows:

(in millions)	
Nuclear fuel [(a)]	$ 925
Growth	600
Production plant	1,125
Total	$ 2,650

(a) Includes Generation s share of the investment in nuclear fuel for the co-owned Salem plant.

ComEd

ComEd is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in northern Illinois. ComEd is a public utility under the Illinois Public Utilities Act subject to regulation by the ICC related to distribution rates and service, the issuance of securities and certain other aspects of ComEd s business. ComEd is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ComEd s business. Specific operations of ComEd are also subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, ComEd is subject to NERC mandatory reliability standards.

ComEd s franchises are sufficient to permit it to engage in the business it now conducts. ComEd s franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2017 to 2066. ComEd anticipates working with the appropriate governmental bodies to extend or replace the franchise agreements prior to expiration.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in the Pennsylvania counties surrounding the City of Philadelphia. PECO is a public utility under the Pennsylvania Public

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Utility Code subject to regulation by the PAPUC related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of PECO s business. PECO is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of PECO s business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Specific operations of PECO are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, PECO is also subject to NERC mandatory reliability standards.

PECO has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities or territories in which it now supplies such services. PECO s authorizations consist of charter rights and certificates of public convenience issued by the PAPUC and/or grandfathered rights, with all of such rights generally unlimited as to time and generally exclusive from competition from other electric and natural gas utilities. In a few defined municipalities, PECO s natural gas service territory authorizations overlap with that of another natural gas utility; however, PECO does not consider those situations as posing a material competitive or financial threat.

BGE

BGE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in central Maryland, including the City of Baltimore, as well as the purchase and regulated retail sale of natural gas and the provision of gas distribution services to retail customers in central Maryland, including the City of Baltimore. BGE is a public utility under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to electric and gas distribution rates and service, the issuances of certain securities and certain other aspects of BGE s business. BGE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of BGE s business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Specific operations of BGE are subject to the jurisdiction of various other Federal, state, regional and local agencies. Additionally, BGE is also subject to NERC mandatory reliability standards.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE s authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are nonexclusive and are perpetual. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MDPSC. The service territory for BGE, as well as for other electric utilities in the state, was precisely delineated in 1966 by the MDPSC and has been modified in minor ways over the years. With respect to natural gas distribution service, BGE s authorizations consist of charter rights, a perpetual state-wide franchise grant and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

PHI

PHI was incorporated in Delaware in 2001. Through its reportable segments Pepco, DPL and ACE, PHI is engaged primarily in the transmission, distribution and default supply of electricity, and, to a lesser extent, the distribution and supply of natural gas. On March 23, 2016, Pepco Holdings, Inc., converted from a Delaware corporation to a Delaware limited liability company, Pepco Holdings LLC. PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries.

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Pepco

Pepco is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services in the District of Columbia and major portions of Prince George s County and Montgomery County in Maryland. Pepco is a public utility under the Code of the District of Columbia and subject to regulation by the DCPSC related to distribution rates and service, the issuance of securities and certain other aspects of Pepco s business in the District of Columbia. Pepco is also an electric company under the Maryland Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to distribution rates and service, the issuance of securities and certain other aspects of Pepco s business in Maryland. Pepco is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of Pepco s business. Additionally, Pepco is subject to NERC mandatory reliability standards.

Pepco s right to occupy public space for utility purposes is by permit from the District of Columbia and the federal government. Pepco is the only public utility that distributes electricity for sale to the public in the District of Columbia. In Maryland, Pepco operates pursuant to state-wide franchises granted by Maryland s General Assembly that are unlimited in duration. Pursuant to statute, public service companies in Maryland may exercise a franchise to the extent authorized by the MDPSC. The service territories for Pepco, as well as for other electric utilities in the state, were precisely delineated in 1966 by the MDPSC and have been modified in minor ways over the years.

DPL

DPL is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in portions of Maryland and Delaware, as well as the purchase and regulated retail sale of natural gas and the provision of natural gas distribution services to retail customers in New Castle County, Delaware. DPL is a public utility under the Delaware Code and subject to regulation by the DPSC related to electric and gas distribution rates and service, the issuance of certain securities and certain other aspects of DPL s business in Delaware. In Maryland, DPL is an electric company under the Public Utilities Article of the Maryland Annotated Code subject to regulation by the MDPSC related to electric rates and service, the issuances of certain securities and certain other aspects of DPL s business in Maryland. DPL is a public utility under the Federal Power Act and is subject to regulation by FERC related to transmission rates and certain other aspects of DPL s business and by the U.S. Department of Transportation related to pipeline safety and other areas of gas operations. Additionally, DPL is also subject to NERC mandatory reliability standards.

DPL has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. In Maryland, DPL operates pursuant to state-wide franchises that are substantially similar in nature to those described above with respect to Pepco s Maryland operations. DPL s exclusive and continuing authority to distribute electricity and natural gas in its non-municipal service territories in Delaware is derived from legislation, through which the DPSC has established exclusive service territories. With respect to municipalities that it serves, DPL provides service under various franchises granted to DPL and predecessor companies, which franchises are generally either unlimited as to time or renew automatically.

ACE

ACE is engaged principally in the purchase and regulated retail sale of electricity and the provision of electricity distribution and transmission services to retail customers in portions of southern New

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Jersey. ACE is a public utility under the New Jersey Public Utilities Act subject to regulation by the NJBPU related to distribution rates and service, the issuance of securities and certain other aspects of ACE s business. ACE is a public utility under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of ACE s business. Additionally, ACE is subject to NERC mandatory reliability standards.

ACE s franchises are sufficient to permit it to engage in the business it now conducts. ACE operates under non-exclusive franchises that have been granted by the NJBPU and under certain non-exclusive consents from municipalities in which ACE provides service. While most of the municipal consents were granted in perpetuity, two of the municipal consents require renewal on a periodic basis in accordance with their terms with respect to ACE s continued right to erect and maintain wires and poles in, upon, over and under the public streets, streets and alleys, and are subject to the ultimate review and approval of the NJBPU. All of the franchises and consents are currently in full force and effect.

ComEd, PECO, BGE, Pepco, DPL and ACE

Utility Operations

Service Territories. The following table presents the size of retail service territories, populations of each retail service territory and the number of retail customers within each retail service territory for the Utility Registrants as of December 31, 2016:

	Retail Service Territories (in square miles)			Retail Service Territory Population (in millions)			Number of Retail Customers (in millions)		
	Total	Electric	Natural gas	Total	Electric	Natural gas	Total	Electric	Natural gas
ComEd	11,400	11,400	n/a	9.4[(a)]	9.4	n/a	4.0	4.0	n/a
PECO	2,100	1,900	1,900	4.6[(b)]	4.0	3.1	2.1	1.6	0.5
BGE	2,300	2,300	800	3.0[(c)]	3.0	2.9	1.3	1.3	0.7
Pepco	640	640	n/a	2.4[(d)]	2.4	n/a	0.9	0.9	n/a
DPL	5,675	5,400	275	2.0[(e)]	1.4	0.6	0.6	0.5	0.1
ACE	2,800	2,800	n/a	1.1[(f)]	1.1	n/a	0.5	0.5	n/a

(a) Includes approximately 2.7 million in the city of Chicago.
(b) Includes approximately 1.6 million in the city of Philadelphia.
(c) Includes approximately 0.6 million in the city of Baltimore.
(d) Includes approximately 0.7 million in the District of Columbia.
(e) Includes approximately 0.1 million in the city of Wilmington.
(f) Includes approximately 0.1 million in the city of Atlantic City.

Peak Deliveries. The Utility Registrants electric sales and peak load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. For PECO, BGE and DPL natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating.

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The following table summarizes historic peak deliveries for the Utility Registrants for electric and gas deliveries during peak demand months through December 31, 2016:

	Electric Peak Deliveries (in GW)				Natural Gas Peak Deliveries (in mmcfs)	
	Summer peak date	**Summer deliveries**	**Winter peak date**	**Winter deliveries**	**Winter peak date**	**Winter deliveries**
ComEd	7/20/2011	23.75	1/6/2014	16.51	n/a	n/a
PECO	7/22/2011	8.98	1/7/2014	7.17	2/15/2015	777
BGE	7/21/2011	7.23	2/20/2015	6.71	2/19/2015	777
Pepco	7/22/2011	7.02	2/20/2015	6.07	n/a	n/a
DPL	7/22/2011	4.14	2/20/2015	4.11	2/15/2015	186
ACE	7/22/2011	2.96	1/7/2014	1.8	n/a	n/a

Electric and Natural Gas Distribution Services. The Utility Registrants are allowed to recover reasonable costs and fair and prudent capital expenditures associated with electric and natural gas distribution services and earn a return on those capital expenditures, subject to commission approval. ComEd recovers costs through a performance-based rate formula, pursuant to EIMA. ComEd is required to file an update to the performance-based rate formula on an annual basis. PECO s, BGE s and DPL s electric and gas distribution costs and Pepco s and ACE s electric distribution costs are recovered through traditional rate case proceedings. In certain instances, the Utility Registrants use specific recovery mechanisms as approved by their respective regulatory agencies.

ComEd, Pepco, and ACE customers have the choice to purchase electricity, and PECO, BGE, and DPL customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. The Utility Registrants remain the distribution service providers for all customers and are obligated to deliver electricity and natural gas to customers in their respective service territories while charging a regulated rate for distribution service. In addition, the Utility Registrants also retain significant default service obligations to provide electricity to certain groups of customers in their respective service areas who do not choose a competitive electric generation supplier. PECO and BGE also retain significant default service obligations to provide natural gas to certain groups of customers in their respective service areas who do not choose a competitive natural gas supplier. For natural gas, DPL does not retain default service obligations. For those customers that choose a competitive electric generation or natural gas supplier, the Utility Registrants may act as the billing agent but do not record revenues or purchased power and fuel expense related to the electricity and/or natural gas. For those customers that choose one of the Utility Registrants as their electric generation or natural gas supplier, the Utility Registrants are permitted to recover electric and natural gas procurement costs from retail customers. Therefore, fluctuations in electric and natural gas procurement costs have no impact on electric and natural gas revenues net of purchased power and fuel expense.

The following table outlines the state regulatory agencies and default service obligations for each of the Utility Registrants:

	Regulatory Agency	**Default Service Obligation-Electricity**	**Default Service Obligation-Natural Gas**
ComEd	ICC	POLR	n/a
PECO	PAPUC	DSP	PGC

BGE	MDPSC	SOS	MBR
Pepco	DCPSC/MDPSC	SOS	n/a
DPL	DPSC/MDPSC	SOS	n/a
ACE	NJBPU	BGS	n/a

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Retail customers participating in customer choice programs, and retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of GWh and mmcf sales, respectively) for the Utility Registrants consisted of the following at December 31, 2016, 2015 and 2014:

	December 31, 2016					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	1,502,900	n/a	38%	n/a	72%	n/a
PECO	587,200	81,300	36%	16%	70%	26%
BGE	337,000	151,000	27%	23%	59%	57%
Pepco	176,372	n/a	21%	n/a	65%	n/a
DPL	78,994	156	15%	0.1%	51%	28%
ACE	94,562	n/a	17%	n/a	47%	n/a

	December 31, 2015					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd [(a)]	1,655,400	n/a	42%	n/a	76%	n/a
PECO	563,400	81,100	35%	16%	70%	25%
BGE	343,000	154,000	27%	23%	61%	56%
Pepco	173,222	n/a	21%	n/a	65%	n/a
DPL	77,603	159	15%	0.1%	51%	31%
ACE	78,299	n/a	14%	n/a	45%	n/a

	December 31, 2014					
	Number of retail customers in customer choice programs		% of total retail customers		Customer choice program deliveries as a % of retail sales (for the year ended)	
	Electric	Natural gas	Electric	Natural gas	Electric	Natural gas
ComEd	2,426,900	n/a	63%	n/a	80%	n/a
PECO	546,900	78,400	34%	16%	70%	22%
BGE	364,000	161,000	29%	25%	60%	53%
Pepco	179,524	n/a	22%	n/a	65%	n/a
DPL	78,153	157	15%	0.1%	53%	31%
ACE	86,780	n/a	16%	n/a	51%	n/a

(a) In September 2015, the City of Chicago discontinued its participation in the customer choice program and began purchasing its electricity from ComEd. Approximately 670,000 customers were impacted by the City of Chicago s decision which resulted in the reduction in the number of customers participating in customer choice programs in 2015.

Procurement-Related Proceedings. The Utility Registrants electric supply for its customers is primarily procured through contracts as required by the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU. The Utility Registrants procure electricity supply from various approved bidders, including Generation. Charges incurred for electric supply procured through contracts with Generation are included in Purchased power from affiliates on the Utility Registrants Statements of Operations and Comprehensive Income.

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PECO s, BGE s and DPL s natural gas supplies are purchased from a number of suppliers for terms of up to three years. PECO, BGE and DPL have annual firm supply and transportation contracts of 132,000 mmcf, 128,000 mmcf and 58,000 mmcf, respectively. In addition, to supplement gas supply at times of heavy winter demands and in the event of temporary emergencies, PECO, BGE and DPL have available storage capacity from the following sources:

	Peak Natural Gas Sources (in mmcf)		
	Liquefied Natural Gas Facility	**Propane-Air Plant**	**Underground Storage Service Agreements (a)**
PECO	1,200	150	18,000
BGE	1,056	550	22,000
DPL	257	n/a	3,800

(a) Natural gas from underground storage represents approximately 28%, 46% and 34% of PECO s, BGE s and DPL s 2016-2017 heating season planned supplies, respectively.

PECO, BGE and DPL have long-term interstate pipeline contracts and also participate in the interstate markets by releasing pipeline capacity or bundling pipeline capacity with gas for off-system sales. Off-system gas sales are low-margin direct sales of gas to wholesale suppliers of natural gas. Earnings from these activities are shared between the utilities and customers. PECO, BGE and DPL make these sales as part of a program to balance its supply and cost of natural gas.

Energy Efficiency Programs. The Utility Registrants are also allowed to recover costs associated with energy efficiency and demand response programs. Each commission approved program seeks to meet mandated electric consumption reduction targets and implement demand response measures to reduce peak demand. The programs are designed to meet standards required by each respective regulatory agency.

Capital Investment. The Utility Registrants businesses are capital intensive and require significant investments, primarily in electric transmission and distribution and natural gas transportation and distribution facilities, to ensure the adequate capacity, reliability and efficiency of their systems. ComEd s, PECO s, BGE s, Pepco s, DPL s and ACE s most recent estimates of capital expenditures for plant additions and improvements for 2017 are $2,200 million, $775 million, $925 million, $625 million, $375 million and $300 million, respectively.

ComEd, PECO, BGE, Pepco and DPL have AMI smart meter and smart grid deployment programs within their respective service territories to enhance their distribution systems. PECO, BGE, Pepco and DPL have completed the installation and activation of smart meters in their respective service territories. ACE has yet to receive approval from the NJBPU to proceed with the installation of AMI smart meters.

Transmission Services. The Utility Registrants provide unbundled transmission service under rates approved by FERC. Under FERC s open access transmission policy promulgated in Order No. 888, the Utility Registrants, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. The Utility Registrants and their affiliates are required to comply with FERC s Standards of Conduct regulation governing the communication of non-public transmission information between the transmission owner s employees and wholesale merchant employees.

PJM is the regional grid operator and operates pursuant to FERC-approved tariffs. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff). PJM operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. The Utility Registrants are members of PJM and provide regional transmission service pursuant to the PJM Tariff. The Utility Registrants and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are under the dispatch control of PJM. Under the PJM Tariff, transmission service is provided on a region-wide, open-access basis using the transmission facilities of the PJM transmission owners at rates based on the costs of transmission service.

ComEd s transmission rates are established based on a formula that was approved by FERC in January 2008. BGE s, Pepco s, DPL s and ACE s transmission rates are established based on a formula that was approved by FERC in April 2006. FERC s orders establish the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO s customers are charged for PECO s PJM retail transmission services on a full and current basis through a Transmission Service Charge (applicable to default service only) and through a Non-Bypassable Transmission Charge (applicable to all distribution customers) in accordance with PECO s approved distribution rates.

See Note 3 Regulatory Matters, Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for additional information regarding transmission services.

Employees

As of December 31, 2016, Exelon and its subsidiaries had 34,396 employees in the following companies, of which 11,984 or 35% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 [(a)]	IBEW Local 614 [(b)]	Other CBAs	Total Employees Covered by CBAs	Total Employees
Generation [(c)]	1,640	99	2,635	4,374	14,717
ComEd	3,777			3,777	6,574
PECO		1,310		1,310	2,651
BGE [(d)]					3,097
PHI [(e)]			331	331	1,670
Pepco [(e)]			1,056	1,056	1,466
DPL [(e)]			631	631	871
ACE [(e)]			399	399	595
Other [(f)]	65		41	106	2,755
Total	5,482	1,409	5,093	11,984	34,396

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 62 employees in ComEd s System Services Group and was renewed in 2016. Generation s and ComEd s separate CBAs with IBEW Local 15 will expire in 2022.

(b) 1,310 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614, both expiring in 2021. Additionally, Exelon Power, an operating unit of Generation, has an agreement covering 99 employees, which was renewed in 2016 and expiring in 2019.

(c) During 2016, Generation finalized its CBA with the Security Officer union at Oyster Creek, expiring in 2022 and New Energy IUOE Local 95-95A, which will expire in 2021. Also during 2016, Pepco Energy Services was allocated to Generation with a total of 358 employees broken down as follows: 229 employees covered by CBAs and 129 non-represented employees. During 2015, Generation finalized its CBA with Clinton Local 51 which will expire in 2020; its two CBAs with Local 369 at Mystic 7 and Mystic 8/9, both expiring in 2020; and four Security Officer unions at Braidwood, Byron, Clinton and TMI, all expiring between 2018 and 2021, respectively. During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively and CENG finalized its CBA with Nine Mile Point which will expire in 2020. Additionally, during 2014, Generation finalized CBAs with the Security Officer unions at Dresden, LaSalle, Limerick and Quad Cities, which expire between 2017 and 2018. Lastly, during 2014, an agreement was negotiated with Las Vegas District Energy and IUOE Local 501, which will expire in 2018. During 2013, Generation finalized two 3-year agreements: New England ENEH, UWUA Local 369, which will expire in 2017.

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(d) In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 will begin negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.
(e) PHI s utility subsidiaries are parties to five collective bargaining agreements with four local unions. Collective bargaining agreements are generally renegotiated every three to five years. All of these collective bargaining agreements were renegotiated in 2014 and were extended through various dates ranging from October 2018 through June 2020
(f) Other includes shared services employees at BSC.

Environmental Regulation

General

The Registrants are subject to comprehensive and complex legislation regarding environmental matters by the federal government and various state and local jurisdictions in which they operate their facilities. The Registrants are also subject to regulations administered by the EPA and various state and local environmental protection agencies. Federal, state and local regulation includes the authority to regulate air, water, and solid and hazardous waste disposal.

The Exelon Board of Directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. Performance of those individuals directly involved in environmental compliance and strategy is reviewed and affects compensation as part of the annual individual performance review process. The Exelon Board of Directors has delegated to its Corporate Governance Committee the authority to oversee Exelon s compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon s climate change and sustainability policies and programs, as discussed in further detail below. The Exelon Board of Directors has also delegated to its Generation Oversight Committee the authority to oversee environmental, health and safety issues relating to Generation. The respective Boards of ComEd, PECO, BGE, Pepco, DPL and ACE oversee environmental, health and safety issues related to these companies.

Air Quality

Air quality regulations promulgated by the EPA and the various state and local environmental agencies in Illinois, Maryland, Massachusetts, New York, Pennsylvania and Texas in accordance with the Federal Clean Air Act impose restrictions on emission of particulates, sulfur dioxide (SO_2), nitrogen oxides (NO_x), mercury and other pollutants and require permits for operation of emissions sources. Such permits have been obtained by Exelon s subsidiaries and must be renewed periodically. The Clean Air Act establishes a comprehensive and complex national program to substantially reduce air pollution from power plants.

See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information regarding clean air regulation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation s power generation facilities

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discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension. Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation s power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by any changes to the existing regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, Riverside and Salem.

On October 14, 2014, the EPA s final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed to determine the best technology available to minimize adverse impacts on aquatic life, followed by an implementation period for the selected technology. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, Generation cannot estimate the effect that compliance with the rule will have on the operation of its generating facilities and its future results of operations, cash flows, and financial position. Should a state permitting director determine that a facility must install cooling towers to comply with the rule, that facility s economic viability could be called into question. However, the potential impact of the rule has been significantly reduced since the final rule does not mandate cooling towers as a national standard and sets forth technologies that are presumptively compliant, and the state permitting director is required to apply a cost-benefit test and can take into consideration site-specific factors.

Pursuant to discussions with the NJDEP in 2010 regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029. The agreement only applies to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon s other plants.

New York Facilities. In July 2011, the New York Department of Environmental Conservation (DEC) issued a policy regarding the best available technology for cooling water intake structures. Through its policy, the DEC established closed-cycle cooling or its equivalent as the performance goal for all existing facilities, but also provided that the DEC will select a feasible technology whose costs are not wholly disproportionate to the environmental benefits to be gained and allows for a site-specific determination where the entrainment performance goal cannot be achieved. The Ginna and Nine Mile Point Unit 1 power generation facilities received renewals of their state water discharge permits in 2014.

Salem. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water system. In February 2006, PSEG filed a renewal application with the NJDEP allowing Salem to continue operating under its existing NPDES permit until a new permit is issued. On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to

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continue to operate utilizing the existing once-through cooling water system with certain required system modifications. On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance.

Solid and Hazardous Waste

CERCLA provides for immediate response and removal actions coordinated by the EPA in the event of threatened releases of hazardous substances into the environment and authorizes the EPA either to clean up sites at which hazardous substances have created actual or potential environmental hazards or to order persons responsible for the situation to do so. Under CERCLA, generators and transporters of hazardous substances, as well as past and present owners and operators of hazardous waste sites, are strictly, jointly and severally liable for the cleanup costs of waste at sites, most of which are listed by the EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with an EPA-directed cleanup, may voluntarily settle with the EPA concerning their liability for cleanup costs, or may voluntarily begin a site investigation and site remediation under state oversight prior to listing on the NPL. Various states, including Delaware, District of Colombia, Illinois, Maryland, New Jersey and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO, BGE, Pepco, DPL and ACE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third-party.

See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd s, PECO s and BGE s environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2017 at Exelon for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $41 million, consisting of $35 million and $6 million respectively, at ComEd and PECO.

Generation s environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2016, Generation has established appropriate contingent liabilities for potential environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

The Utility Registrants also have environmental liabilities for remediation considerations. As of December 31, 2016, Generation has established appropriate contingent liabilities for potential environmental remediation requirements.

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In addition, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE may be required to make significant additional expenditures not presently determinable for other environmental remediation costs.

See Notes 3 Regulatory Matters and 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants environmental remediation efforts and related impacts to the Registrants results of operations, cash flows and financial positions.

Global Climate Change

Exelon has utility and generation assets, and customers, that are subject to the effects of climate change as described in the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report, published in 2014, Accordingly the company is engaged in a variety of initiatives to better understand and develop responses to these issues, including investments in resiliency, partnering with federal, state and local governments and advocating for science-based public policy. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small greenhouse gas (GHG) emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation s emission intensity, or rate of carbon dioxide equivalent (CO2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants (primarily natural gas); CO2, methane and nitrous oxide are all emitted in this process, with CO2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represented the majority of Exelon s direct GHG emissions in 2016, although less than 30 percent of its owned generating capacity utilizes fossil fuels with less than 10 percent of owned generation MWh actually produced by fossil fuels as Exelon s fossil-fired generation is primarily intermediate and peaking in nature. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and fossil fuel generation of electricity used to power its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

Climate Change Regulation. Exelon is or may become subject to climate change regulation or legislation at the Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States is a Party to the United Nations Framework Convention on Climate Change (UNFCCC). The Parties to the UNFCCC adopted the Paris Agreement at the 21st session of the UNFCCC Conference of the Parties (COP 21) on December 12, 2015. The Paris Agreement defines the UNFCCC s objective of limiting the global temperature increase to 1.5°C above pre-industrial levels. All Parties are required to develop their own national emission reductions and to update those reductions at least every five years. The Developed Country Parties, including the United States, are required to take the lead by undertaking economy-wide absolute emission reduction targets. The United States had previously submitted its national emission reductions to achieve a 2020 target of reducing net emissions to 17% below the 2005 level and to achieve net greenhouse gas emission reductions of 26% 28% below the 2005 level by 2025. The United States has indicated that it intends to achieve these reductions through a variety of mechanisms, including regulations to cut carbon pollution from new and existing power plants. The Paris Agreement entered into force on November 4, 2016 the thirtieth day after the date on which at

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least 55 Parties accounting for at least an estimated 55% of total global greenhouse gas emissions ratified the Agreement. The Agreement has not been ratified by the US Senate and it is uncertain whether or not or to what extent the new Trump Administration will pursue the established target.

Federal Climate Change Legislation and Regulation. It is highly uncertain that Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits.

Under the Obama Administration, the EPA proposed and finalized regulations for new and modified fossil-fuel power plants under Section 111(b) of the Clean Air Act and Section 111(d) for existing fossil-fuel power plants. These regulations are currently being litigated. The 111(d) regulations, referred to as the Clean Power Plan, are currently subject to a stay by the Supreme Court, pending conclusion of all litigation at both the D.C. Circuit and Supreme Court levels. The D.C. Circuit heard *en banc* oral argument in late September 2016, but has not yet issued its decision. Prior to the stay, the Clean Power Plan had established GHG emission reduction targets for each state, with emission reductions slated to begin in 2022. State requirements to submit plans to EPA in September 2016 (or within two years if an extension was requested) were placed in abeyance pending results of litigation.

President Trump s election platform called for eliminating a number of EPA regulations, including the Clean Power Plan. Due to the need to appoint and confirm key EPA officials as the Trump Administration begins to govern, the specific details of the Trump Administration s plans to address the Clean Power Plan are not known. In the interim, the D.C. Circuit continues its review of the regulation under existing litigation and is expected to issue its decision in the first half of 2017.

Due to current litigation and the need for the new Administration to develop its approach to dealing with the Clean Power plan, Exelon and Generation cannot at this time predict the future of the Clean Power Plan or individual state responses to Clean Power Plan developments or how developments will impact their future financial positions, results of operations and cash flows.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program the regional RGGI CO_2 budget was reduced, starting in 2014, from its previous 165 million ton level to 91 million tons, with a 25 percent reduction in the cap level each year from 2015 through 2020. Included in the program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO_2 allowances available for purchase at auction. (CCR trigger prices are $6 in 2015, $8 in 2016 and $10 in 2017; after 2017 the CCR price increases by 2.5 percent each year). Allowance prices in 2016 remained below the applicable CCR trigger price, indicating program costs remained within the boundaries of costs acceptable to participating states. During 2016, RGGI began its quadrennial review process to determine what, if any, program design amendments should be pursued for the regional program. A series of stakeholder calls occurred in 2016, which included discussion around potential linkage issues with the federal Clean Power Plan, linkages to state GHG emission reduction goals/programs, functioning of cost containment mechanisms, and consideration of whether future cap levels should be adjusted for the post-2020 period. RGGI intends to complete its program review in early 2017.

On December 18, 2009, Pennsylvania issued the state s final Climate Change Action Plan. The plan sets as a target a 30 percent reduction in GHG emissions by 2020. The Climate Change Advisory Committee continues to meet quarterly to review Climate Action Work Plans for the residential, commercial and industrial sectors. The Climate Change Action Plan does not impose any requirements on Generation or PECO at this time.

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The Maryland Commission on Climate Change was chartered in 2007 and released a greenhouse gas reduction strategy with 42 recommendations on August 27, 2008. The plan s primary policy recommendation to formally adopt science-based regulatory goals to reduce Maryland s green house gas emissions (GHG) was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA) which required Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It also directed the Maryland Department of Environment to prepare and implement an action plan which listed Maryland s electricity consumption reduction goals, required under the EmPOWER Maryland program, and mandatory State participation in RGGI Program, as the energy sector s contribution to the plan. In April 2016, the Governor of Maryland signed the GGRA of 2016 into law, which updated the state s Climate Commission charter. It expanded membership to include more non-governmental members and established an enhanced statewide GHG emissions reduction target of 40 percent from 2006 levels by 2030, maintaining the caveats from the 2007 legislation that the implementation have a net positive impact on both jobs and the economy. MDE is currently working on plans to meet the 2016 GGRA requirements. In February of this year (2017) , the Maryland General Assembly overrode Maryland Governor Hogan s veto of legislation that requires the current Renewable Portfolio Standard (RPS) to be accelerated and enhanced. The law requires the RPS, previously set at 20% renewables by 2022, with a 2% solar carve out, to move to 25% renewables by 2020 with a 2.5% solar carve out.

Exelon s Voluntary Climate Change Efforts. In a world increasingly concerned about global climate change and regulatory action to reduce GHG, Exelon s low-carbon generating fleet is seen by management as a competitive advantage. Exelon remains one of the largest, lowest carbon electric generators in the United States: nuclear for base load, natural gas for marginal and peak demand, hydro and pumped storage, and supplemental wind and solar renewables. As further legislation and regulation imposing requirements on emissions of GHG and air pollutants are promulgated, Exelon s low-carbon, low-emission generation fleet will position the company to benefit from its comparative advantage over other generation fleets.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia have adopted some form of RPS requirement. Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware and New Jersey have laws specifically addressing energy efficiency and renewable energy initiatives. In addition to state level activity, RPS legislation has been considered and may be considered again in the future by the United States Congress. Also, states that currently do not have RPS requirements may adopt such legislation in the future.

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

In accordance with FEJA that takes effect on June 1, 2017, beginning with the plan or plans to be implemented in the 2017 delivery year, the IPA shall develop a long term renewable resources procurement plan (LT Plan). The RPS target percentages for the overall service territory have not changed through June 1, 2025 (11.5% of retail load by June 1 2016 growing to 25% by June 1 2025) although FEJA extended the 25% RPS target to delivery years after 2025. Currently, each Retail

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Electric Supplier and each utility is responsible for the renewable resource obligation for the customers to which it supplies power. Over time, this will change and the utility will procure renewable resources based on the retail load of substantially all customers in its service territory. For the delivery year beginning June 1, 2017, the LT Plan shall include cost effective renewable energy resources procured by the utility for the retail load the utility supplies and for 50% of the retail customer load supplied by Retail Electric Suppliers in the utility service territory on February 28, 2017. Utility procurement for RES supplied retail customer load will increase to 75% June 1, 2018 and to 100% beginning June 1, 2019.

Originally passed November 30, 2004 the AEPS Act became effective for PECO on January 1, 2011. During 2016, PECO was required to supply approximately 5.5% of electric energy generated from Tier I alternative energy resources (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania), as measured in AECs, through May 31, 2016 and subsequently 6.0% beginning June 1, 2016 and continuing through May 31, 2017. PECO is also required to supply 8.2% of electric energy generated from Tier II alternative energy resources (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology), as measured in AECs, effective June 1, 2015 and continuing through May 31, 2020. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO purchases its AECs through its DSP Program full requirement contracts with various counterparties, including Generation. PECO also obtains AECs of Solar Tier I annually from long term agreements with various counterparties, including Generation, and balancing amounts of Tier 1 non-solar and Tier II through broker purchases.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2015, 10.5% was required from Tier 1 renewable sources, including at least 0.5% derived from solar energy and 2.5% from Tier 2 renewable sources. BGE, Pepco and DPL are subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources. In addition, the wholesale suppliers that supply power to BGE, Pepco and DPL through SOS procurement auctions have the obligation, by contract with BGE, Pepco and DPL, to meet the RPS requirements.

Section 34-1432 of the D.C. Code sets forth the RPS requirement, which applies to all retail electricity sales in the District of Columbia by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, certain qualifying biomass, methane from anaerobia decomposition of organic materials in landfill or wastewater treatment plant, geothermal, ocean, and fuel cell) and Tier 2 sources (hydroelectric (other than pumped storage generation), certain qualifying biomass and waste-to-energy). The RPS requirement began in 2007, with standards increasing annually. For 2017, the RPS requires that suppliers procure 13.1% and 2.5% from Tier 1 and Tier 2 sources, respectively, with not less than 0.95% solar, and escalating in 2023 to 20.0% from Tier 1 sources, including at least 2.5% from solar energy, and a phase out of Tier 2 resource options. In 2015 the law was amended to extend the RPS requirements to 2032, at which time not less than 50% is required from Tier 1 renewable sources, including at least 5.0% derived from solar energy. Tier 2 renewable sources remain phased out. The wholesale suppliers that supply power to Pepco through SOS procurement auctions have the obligation, by contract with Pepco, to meet the RPS requirements.

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Title 26 of the Delaware Code sets forth the RPS requirement, which applies to retail electricity sales in Delaware by electricity suppliers. The RPS requirement requires that DPL obtain a specified percentage of the electricity it delivers to its eligible customers from eligible energy resources (solar electric, wind, ocean tidal, ocean thermal, fuel cells powered by renewable fuels, hydroelectric facilities with a maximum capacity of 30 MW, sustainable biomass, anaerobic digestion and landfill gas). The RPS requirement, beginning in 2007, required that suppliers procure 2.0% from eligible energy resources, with not less than 0.011% from solar, and escalating annually through 2025, at which time suppliers must procure 25.0% from eligible energy resources, including at least 3.5% from solar. As of December 31, 2016, DPL is a party to three land-based wind power purchase agreements in the aggregate amount of 128 MWs (nameplate capacity). DPL has contracted for approximately 48 MW of Solar Renewable Energy Credits (SRECs) through a combination of long term SREC purchase agreements with solar facilities, SREC Purchase agreements with the Delaware Sustainable Energy Utility and the DE SREC Procurement Program. On October 18, 2011, the DPSC approved a tariff submitted by DPL in accordance with the requirements of the RPS specific to a fuel cell facility totaling 30 MWs to be constructed by a qualified fuel cell provider. The tariff and the RPS establish that DPL acts solely as an agent to collect payments in advance from its distribution customers and remit them to the qualified fuel cell provider for each MWh of energy produced by the fuel cell facilities through 2033. The qualified fuel cell provider output reduces the non-solar and/or solar requirements needed to satisfy the Delaware RPS obligations.

The Electric Discount and Energy Competition Act, (EDECA), was signed into law in 1999, and includes the requirement for compliance with New Jersey s RPS by electric power suppliers and providers of BGS. The RPS requires that electric power suppliers obtain a specified percentage of the electricity they sell from Class I sources (solar, wind, wave/tidal action, geothermal, methane captured from landfills, fuel cells with certain types of power sources, and biomass) and Class II sources (hydroelectric facilities with a combined design capacity of less than 30 MW, and certain resource recovery facilities). In 2010, the Solar Energy Advancement and Fair Competition Act, (SEAFCA), was signed into law. SEAFCA amended several provisions of EDECA, among them the manner in which suppliers were to comply with the solar portion of the RPS. SEAFCA, beginning in energy year 2011, set out a specific requirement for solar energy generation. The Solar Act of 2012 made further changes effective for energy year 2014 and beyond. The RPS requirement has changed over time. For energy year 2005, suppliers were required to procure 0.74% and 2.5% from Class I and Class II sources, respectively. For the most recently completed energy year 2016, 9.649% was required from Class I renewable sources, 2.5% from Class II renewable sources, and 2.75% from solar energy. As noted above, the RPS applies to each supplier or provider that sells electricity to retail customers in New Jersey. Pursuant to Section 14:4-1.2 of the New Jersey Administrative Code, electric public utilities, such as ACE, that provide electric generation services only for the purpose of providing BGS are not electric power suppliers and so are not subject to the RPS procurement requirements.

Similar to ComEd, PECO, BGE, Pepco, DPL and ACE, Generation s retail electric business must source a portion of the electric load it serves in many of the states in which it does business from renewable resources or approved equivalents such as RECs. Potential regulation and legislation regarding renewable and alternative energy resources could increase the pace of development of wind and other renewable/alternative energy resources, which could put downward pressure on wholesale market prices for electricity in some markets where Exelon operates generation assets. At the same time, such developments may present some opportunities for sales of Generation s renewable power, including from wind, solar, hydroelectric and landfill gas.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on renewable portfolio standards.

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Executive Officers of the Registrants as of February 13, 2017

Exelon

Name	Age	Position	Period
Crane, Christopher M.	58	Chief Executive Officer, Exelon	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		Chairman, PHI	2016 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
Cornew, Kenneth W.	51	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O Brien, Denis P.	56	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Vice Chairman, PHI	2016 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012
Pramaggiore, Anne R.	58	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Adams, Craig L.	64	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Butler, Calvin G.	47	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Velazquez, David M.	57	President and Chief Executive Officer, PHI	2016 - Present
		President and Chief Executive Officer, Pepco, DPL and ACE	2009 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
Von Hoene Jr., William A.	63	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
Thayer, Jonathan W.	45	Senior Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012

Aliabadi, Paymon	54	Executive Vice President and Chief Enterprise Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
DesParte, Duane M.	53	Senior Vice President and Corporate Controller, Exelon	2008 - Present

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Generation

Name	Age	Position	Period
Cornew, Kenneth W.	51	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
Pacilio, Michael J.	56	Executive Vice President and Chief Operating Officer, Exelon Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
		Chief Operating Officer, Exelon Nuclear	
Hanson, Bryan C.	51	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
Nigro, Joseph	52	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	54	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
Wright, Bryan P.	50	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Bauer, Matthew N.	40	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016
		Vice President of Power Finance, Exelon Power	2012 - 2014
		Director, FP&A and Retail, Constellation	2012 - 2012
		Executive Director, Corporate Development, Constellation	2009 - 2012

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ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	58	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
Donnelly, Terence R.	56	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
Trpik Jr., Joseph R.	47	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
Jensen, Val	61	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
Gomez, Veronica	47	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2017 - Present
		Vice President and Deputy General Counsel, Litigation, Exelon	2012 - 2017
Marquez Jr., Fidel	55	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
Brookins, Kevin B.	55	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
McGuire, Timothy M.	58	Senior Vice President, Distribution Operations, ComEd	2016 - Present
		Vice President, Transmission and Substations, ComEd	2010 - 2016
Kozel, Gerald J.	44	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012

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PECO

Name	Age	Position	Period
Adams, Craig L.	64	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	53	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	51	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
Webster Jr., Richard G.	55	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	57	Senior Vice President, Governmental and External Affairs, PECO	2016 - Present
		Vice President, Governmental and External Affairs, PECO	2012 - 2016
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	56	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	70	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
Bailey, Scott A.	40	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012

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BGE

Name	Age	Position	Period
Butler, Calvin G.	47	Chief Executive Officer, BGE	2014 - Present
		Senior Vice President, Regulatory and External Affairs, BGE	2013 - 2014
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
Woerner, Stephen J.	49	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
Case, Mark D.	55	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Biagiotti, Robert D.	47	Vice President, Customer Operations and Chief Customer Officer, BGE	2015 - Present
		Vice President, Gas Distribution, BGE	2011 - 2015
Gahagan, Daniel P.	63	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	44	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2016 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2014 - 2016
		Vice President and Controller, BGE	2012 - 2014
		Executive Director, Audit, Constellation	2010 - 2012
Holmes, Andrew W.	48	Vice President and Controller, BGE	2016 - Present
		Director, Generation Accounting, Exelon	2013 - 2016
		Director, Derivatives and Technical Accounting, Exelon	2008 - 2013
Núñez, Alexander G.	45	Senior Vice President, Regulatory and External Affairs, BGE	2016 - Present
		Vice President, Governmental and External Affairs, BGE	2013 - 2016
		Director, State Affairs, BGE	2012 - 2013

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PHI, Pepco, DPL and ACE

Name	Age	Position	Period
Velazquez, David M.	57	President and Chief Executive Officer, PHI	2016 - Present
		Executive Vice President, Pepco Holdings, Inc.	2009 - 2016
		President and Chief Executive Officer, Pepco, DPL and ACE	2009 - Present
Anthony, J. Tyler	52	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Kinzel, Donna J.	49	Senior Vice President and Chief Financial Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President, Treasurer and Chief Risk Officer, Pepco Holdings	2012 - Present
Bonney, Paul R.	58	Senior Vice President, Legal and Regulatory Strategy, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President and General Counsel, Constellation Energy	2012 - 2016
Parker, Kenneth J.	54	Senior Vice President, Governmental and External Affairs, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Government Affairs and Corporate Citizenship, Pepco Holdings, Inc.	2012 - 2016
Stark, Wendy E.	44	Vice President and General Counsel, PHI, Pepco DPL and ACE	2016 - Present
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - Present
McGowan, Kevin M.	55	Vice President, Regulatory Policy and Strategy	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Aiken, Robert M.	50	Vice President and Controller, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President and Controller, Generation	2012 - 2016
		Executive Director and Assistant Controller, Constellation	2011 - 2012

ITEM 1A. RISK FACTORS

Each of the Registrants operates in a market and regulatory environment that poses significant risks, many of which are beyond that Registrant s control. Management of each Registrant regularly meets with the Chief Enterprise Risk Officer and the RMC, which comprises officers of the Registrants, to identify and evaluate the most significant risks of the Registrants businesses and the appropriate steps to manage and mitigate those risks. The Chief Enterprise Risk Officer and senior executives of the Registrants discuss those risks with the Finance and Risk Committee and Audit Committee of the Exelon Board of Directors and the ComEd, PECO, BGE, and PHI boards of directors. In addition, the generation oversight committee of the Exelon board of directors evaluates risks related to the generation business. The risk factors discussed below could adversely affect one or more of the Registrants results of operations or cash flows and the market prices of their publicly traded securities. Each of the Registrants has disclosed the known material risks that affect its business at this time. However, there may be further risks and uncertainties that are not presently known or that are not currently believed by a Registrant to be material that could adversely affect its performance or financial condition in the future.

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Exelon s financial condition and results of operations are affected to a significant degree by: (1) Generation s position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of the Utility Registrants as operators of electric transmission and distribution systems in six of the largest metropolitan areas in the United States. Factors that affect the financial condition and results of operations of the Registrants fall primarily under the following categories, all of which are discussed in further detail below:

Market and Financial Factors. Exelon s and Generation s results of operations are affected by price fluctuations in the energy markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular the price of natural gas, which affects the prices that Generation can obtain for the output of its power plants, (2) the presence of other generation resources in the markets in which Generation s output is sold, (3) the demand for electricity in the markets where the Registrants conduct their business, and (4) the impacts of on-going competition in the retail channel.

Regulatory and Legislative Factors. The regulatory and legislative factors that affect the Registrants include changes to the laws and regulations that govern competitive markets and utility cost recovery and environmental policy. In particular, Exelon s and Generation s financial performance could be affected by changes in the design of competitive wholesale power markets or Generation s ability to sell power in those markets. In addition, potential regulation and legislation, including regulation or legislation regarding climate change and renewable portfolio standards, could have significant effects on the Registrants. Also, returns for the Utility Registrants are influenced significantly by state regulation and regulatory proceedings.

Operational Factors. The Registrants operational performance is subject to those factors inherent in running the nation s largest fleet of nuclear power reactors and large electric and gas distribution systems. The safe and effective operation of the nuclear facilities and the ability to effectively manage the associated decommissioning obligations as well as the ability to maintain the availability, reliability and safety of its energy delivery systems are fundamental to Exelon s ability to protect and grow shareholder value. Additionally, the operating costs of the Utility Registrants and the opinions of their customers and regulators, are affected by those companies ability to maintain the reliability and safety of their energy delivery systems.

Risks Related to the PHI Merger. Exelon is subject to additional risks related to the merger with PHI that closed on March 23, 2016.

A discussion of each of these risk categories and other risk factors is included below.

Market and Financial Factors

Generation is exposed to depressed prices in the wholesale and retail power markets, which could negatively affect its results of operations or cash flows. (Exelon and Generation)

Generation is exposed to commodity price risk for the unhedged portion of its electricity generation supply portfolio. Generation s earnings and cash flows are therefore subject to variability of spot and forward market prices in the markets in which it operates rise and fall.

Price of Fuels: The spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Thus, the market price of power is affected by the market price of the marginal fuel used to generate the electricity unit. Often, the next unit of electricity will be supplied from generating stations fueled by fossil fuels. Consequently, changes in the market price of fossil fuels often result in comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing downward pressure on natural gas prices and, therefore, on power prices. The continued addition of supply from new alternative generation resources, such as wind and solar, whether mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation, could displace a higher marginal cost plant, further reducing power prices. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution from fossil fuel generation is not factored into market prices.

Demand and Supply: The market price for electricity is also affected by changes in the demand for electricity and the available supply of electricity. Unfavorable economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs could each depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on electricity market prices. The tepid economic environment in recent years and growing energy efficiency and demand response initiatives have limited the demand for electricity in Generation s markets. In addition, in some markets, the supply of electricity through wind or solar generation, when combined with other base-load generation such as nuclear, could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants. Increased supply in excess of demand is furthered by the continuation of RPS mandates and subsidies for renewable energy.

Retail Competition: Generation s retail operations compete for customers in a competitive environment, which affects the margins that Generation can earn and the volumes that it is able to serve. In periods of sustained low natural gas and power prices and low market volatility, retail competitors can aggressively pursue market share because the barriers to entry can be low and wholesale generators (including Generation) use their retail operations to hedge generation output. Increased or more aggressive competition could adversely affect overall gross margins and profitability in Generation s retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon s and Generation s results of operations or cash flows, and such impacts could be emphasized given Generation s concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon s and Generation s ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon s and Generation s result of operations through accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of decommissioning costs, which can be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon s and Generation s results of operations, cash flows or financial position. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and could negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform under their obligations for operational or financial reasons. In the event the counterparties to these

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arrangements fail to perform, Generation could be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTOs and ISOs, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties. In addition, Generation s retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies, governmental entities and residential customers. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that could be incurred due to the nonpayment of a customer s account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Market Designs. The wholesale markets vary from region to region with distinct rules, practices and procedures. Changes in these market rules, problems with rule implementation, or failure of any of these markets could adversely affect Generation s business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

The Registrants are potentially affected by emerging technologies that could over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (All Registrants)

Some of these technologies include, but are not limited, to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles, distributed generation and energy storage devices. Such developments could affect the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants results of operations, cash flows or financial position through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Market performance and other factors could decrease the value of NDT funds and employee benefit plan assets and could increase the related employee benefit plan obligations, which then could require significant additional funding. (All Registrants)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy could adversely affect the value of the investments held within Generation s NDTs and Exelon s employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which could fall below the Registrants projected return rates. A decline in the market value of the NDT fund investments could increase Generation s funding requirements to decommission its nuclear plants. A decline in the market value of the pension and OPEB plan assets will increase the funding requirements associated with Exelon s pension and OPEB plan obligations. Additionally, Exelon s pension and OPEB plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements could also increase the costs and funding requirements of

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the obligations related to the pension and OPEB plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors cannot be recovered, or cannot be recovered in a timely manner, from the Utility Registrants customers, the results of operations and financial position of the Utility Registrants could be negatively affected. Ultimately, if the Registrants are unable to manage the investments within the NDT funds and benefit plan assets, and are unable to manage the related benefit plan liabilities, their results of operations, cash flows or financial position could be negatively impacted.

Unstable capital and credit markets and increased volatility in commodity markets could adversely affect the Registrants businesses in several ways, including the availability and cost of short-term funds for liquidity requirements, the Registrants ability to meet long-term commitments, Generation s ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could negatively impact the Registrants results of operations, cash flows or financial position. (All Registrants)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short-term liquidity needs if internal funds are not available from the Registrants respective operations. Disruptions in the capital and credit markets in the United States or abroad could adversely affect the Registrants ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants access to funds under their credit facilities depends on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation s hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2016, approximately 23%, or $2.2 billion of the Registrants available credit facilities were with European banks. The credit facilities include $9.5 billion in aggregate total commitments of which $7.9 billion was available as of December 31, 2016. As of December 31, 2016, there was $75 million of borrowings under Generation s bilateral credit facilities. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that could affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long-term contracts, which could have a material adverse effect on Exelon s and Generation s results of operations or cash flows.

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If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards in its agreements with its counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (All Registrants)

Generation s business is subject to credit quality standards that could require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which could have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time depends on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry in general, or Generation in particular, has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation. Generation has project-specific financing arrangements and must meet the requirements of various agreements relating to those financings. Failure to meet those arrangements could give rise to a project-specific financing default which, if not cured or waived, could result in the specific project being required to repay the associated debt or other borrowings earlier than otherwise anticipated, and if such repayment were not made, the lenders or security holders would generally have rights to foreclose against the project assets and related collateral.

The Utility Registrants operating agreements with PJM and PECO s, BGE s and DPL s natural gas procurement contracts contain collateral provisions that are affected by their credit rating and market prices. If certain wholesale market conditions were to exist and the Utility Registrants were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the forms of letters of credit or cash, which could have a material adverse effect upon their liquidity. Collateral posting requirements will generally increase as market prices rise and decrease as market prices fall. Collateral posting requirements for PECO, BGE and DPL, with respect to their natural gas supply contracts, will generally increase as forward market prices fall and decrease as forward market prices rise. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if the Utility Registrants were downgraded, they could experience higher borrowing costs as a result of the downgrade.

A Utility Registrant could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general, or a Utility Registrant in particular, has deteriorated. A Utility Registrant could experience a downgrade if its current regulatory environment becomes less predictable by materially lowering returns for the Utility Registrant or adopting other measures to limit utility rates. Additionally, the ratings for a Utility Registrant could be downgraded if its financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage its capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of the Utility Registrants.

The Utility Registrants conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that the Utility Registrants are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate the Utility Registrants from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as ring-

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fencing) could help avoid or limit a downgrade in the credit ratings of the Utility Registrants in the event of a reduction in the credit rating of Exelon. Despite these ring-fencing measures, the credit ratings of the Utility Registrants could remain linked, to some degree, to the credit ratings of Exelon. Consequently, a reduction in the credit rating of Exelon could result in a reduction of the credit rating of some or all of the Utility Registrants. A reduction in the credit rating of a Utility Registrant could have a material adverse effect on the Utility Registrant.

See Liquidity and Capital Resources Recent Market Conditions and Security Ratings for further information regarding the potential impacts of credit downgrades on the Registrants cash flows.

Generation s financial performance could be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

Generation depends on nuclear fuel and fossil fuels to operate most of its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. Natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that could negatively affect the results of operations or cash flows for Generation.

Generation s risk management policies cannot fully eliminate the risk associated with its commodity trading activities. (Exelon and Generation)

Generation s asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations could be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy-related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions could have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products and enters into financial contracts to manage risk and hedge various positions in Generation s power generation portfolio. Generation is exposed to volatility in financial results for unhedged positions.

Financial performance and load requirements could be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation s power portfolio is used to provide power under procurement contracts with the Utility Registrants and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation s output is sold in the wholesale power markets. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation s financial results could be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

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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. (All Registrants)

Potential Corporate Tax Reform. The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform and House Republicans plan to advance their tax reform blueprint . Tax reform proposals call for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. It is uncertain whether, to what extent or when these or any other changes in federal tax policies will be enacted or the transition time frame for such changes. Further, for the Utility Registrants, regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund excess deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

Tax reserves. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves established for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. See Notes 1 Significant Accounting Policies and Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates and the impact of economic downturns could lead to greater expense for uncollectible customer balances. Additionally, increased rates could lead to decreased volumes delivered. Both of these factors could decrease Generation s and the Utility Registrants results from operations or cash flows. (All Registrants)

The Utility Registrants current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd s, PECO s and ACE s costs of purchased power are charged to customers without a return or profit component. BGE s, Pepco s and DPL s SOS rates charged to customers recover their wholesale power supply costs and include a return component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. For BGE, purchased natural gas costs are charged to customers using a MBR mechanism that compares the actual cost of gas to a market index. The difference between the actual cost and the market index is shared equally between shareholders and customers. For DPL, purchased natural gas costs are charged to customers using a GCR mechanism that compares the actual cost of gas to a forecasted amount. The difference between the actual cost and the forecast is fully recoverable and carried forward as a recovery balance in the next GCR filing. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas could result in declines in customer usage, lower revenues and potentially additional uncollectible accounts expense for the Utility Registrants. In addition, any challenges by the regulators or the Utility Registrants as to the recoverability of these costs could have a material effect on the Registrants results of operations or cash flows. Also, the Utility Registrants cash flows could be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

Further, the impacts of economic downturns on the Utility Registrants customers, such as unemployment for residential customers and less demand for products and services provided by

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commercial and industrial customers, and the related regulatory limitations on residential service terminations, could result in an increase in the number of uncollectible customer balances , which would negatively impact the Utility Registrants results of operations or cash flows. Generation s customer-facing energy delivery activities face similar economic downturn risks, such as lower volumes sold and increased expense for uncollectible customer balances which could negatively affect Generation s results of operations or cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants credit risk.

The effects of weather could impact the Registrants results of operations or cash flows. (All Registrants)

Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd, PECO, DPL and ACE. Due to revenue decoupling, BGE, Pepco and DPL recognize revenues at MDPSC and DCPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and are not affected by actual weather with the exception of major storms. Pursuant to the Illinois FEJA signed into law on December 2016 and effective in 2017, ComEd can eliminate the favorable or unfavorable impacts of weather or load on its electric distribution revenues by either (1) revising its electric distribution formula rate to eliminate the ROE collar beginning with the reconciliation performed for the 2017 calendar year or (2) implementing a decoupling tariff if the electric distribution formula rate were to be terminated at anytime.

Extreme weather conditions or damage resulting from storms could stress the Utility Registrants transmission and distribution systems, communication systems and technology, resulting in increased maintenance and capital costs and limiting each company s ability to meet peak customer demand. These extreme conditions could have detrimental effects on the Utility Registrants results of operations or cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and could make period comparisons less relevant.

Generation s operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation could require greater resources to meet its contractual commitments. Extreme weather conditions or storms could affect the availability of generation and its transmission, limiting Generation s ability to source or send power to where it is sold. In addition, drought-like conditions limiting water usage could impact Generation s ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, could have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long-lived assets and other assets recorded on the Registrants statements of financial position could become impaired, which would result in write-offs of the impaired amounts. (All Registrants)

Long-lived assets represent the single largest asset class on the Registrants statements of financial position. Specifically, long-lived assets account for 62%, 54%, 68%, 70%, 81%, 76%, 79% and 73% of total assets for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE, respectively, as of December 31, 2016. In addition, Exelon and Generation have significant balances related to unamortized energy contracts, as further disclosed in Note 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements. The Registrants evaluate the recoverability of

the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset to fair value through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants results of operations.

As of December 31, 2016, Exelon s $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 upon the formation of Exelon and $4.0 billion at PHI primarily resulting from Exelon s acquisition of PHI in the first quarter of 2016. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written-off to expense, which will also reduce equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon s, ComEd s, and PHI s results of operations.

Regulatory actions or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd s, Pepco s, DPL s, and ACE s business, and the fair value of debt, could potentially result in future impairments of Exelon s, PHI s, and ComEd s goodwill, which could be material.

See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Critical Accounting Policies and Estimates and Note 7 Property, Plant and Equipment, Note 8 Impairment of Long Lived Assets and Note 11 Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

Exelon and its subsidiaries at times guarantee the performance of third parties, which could result in substantial costs in the event of non-performance by such third parties. In addition, the Registrants could have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants could incur substantial costs in the event that the applicable Registrant is unable to enforce those agreements or the applicable third-party is otherwise unable to perform. The Registrants could also incur substantial costs in the event that third parties are entitled to indemnification related to environmental or other risks in connection with the acquisition and divestiture of assets. (All Registrants)

Some of the Registrants have issued guarantees of the performance of third parties, which obligate the Registrant or its subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, a Registrant could incur substantial cost to fulfill its obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrant. Some of the Registrants have issued indemnities to third parties regarding environmental or other matters in connection with purchases and sales of asset and a Registrant could incur substantial costs to fulfill its obligations under these indemnities.

Some of the Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected

Registrant could be held responsible for the obligations, which could impact that Registrant s results of operations, cash flows or financial position. In connection with Exelon s 2001 corporate restructuring, Generation assumed certain of ComEd s and PECO s rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd s or PECO s results of operations, cash flows or financial position.

Regulatory and Legislative Factors

The Registrants generation and energy delivery businesses are highly regulated and could be subject to regulatory and legislative actions that adversely affect their operations or financial results. Fundamental changes in regulation or legislation or violation of tariffs or market rules and anti-manipulation laws, could disrupt the Registrants business plans and adversely affect their operations or financial results. (All Registrants)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon s and Generation s operating results and cash flows are significantly affected by Generation s sale of power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon s and the Utility Registrants operating results and cash flows are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant and understand rule changes or Registrant actions that could result in potential violation of tariffs, market rules and anti-manipulation laws. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants businesses would require changes in their business planning models and operations and could negatively impact their respective results of operations, cash flows or financial position.

Regulatory and legislative developments related to climate change and RPS could also significantly affect Exelon s and Generation s results of operations, cash flows or financial position. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, could sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation s Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation s nuclear assets under a carbon constrained regulatory regime that might exist in the future. Similarly, final regulations under Section 111(d) of the Clean Air Act may not provide sufficient incentives for states to utilize carbon-free nuclear power as a means of meeting greenhouse gas emission reduction requirements, while continuing a policy of favoring renewable energy sources. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals could become law or what their effect will be on the Registrants.

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Generation could be negatively affected by possible Federal or state legislative or regulatory actions that could affect the scope and functioning of the wholesale markets. (Exelon and Generation)

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns, or are themselves raising concerns, that energy prices in wholesale markets are too high or insufficient generation is being built because the competitive model is not working and, therefore, are considering some form of re-regulation or some other means of reducing wholesale market prices or subsidizing new generation. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 65% of Generation s generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation s future results of operations will depend on (1) FERC s continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM s, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC s RFP for new gas-fired generation in Maryland. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC s application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC s tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation s authority to sell at market-based rates and none denying that authority.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (swaps), including mandatory clearing for certain categories of swaps, incentives to shift swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based swaps including commodity swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law s objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC s Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using swaps without being subject to mandatory clearing, and accepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemaking proceedings that have not yet been finalized, including the capital and margin rules for (non-cleared) swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation s swap counterparties could be subject to additional and potentially significant

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capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements could impact its cash flows or financial position, but such impacts could be material.

The Utility Registrants could also be subject to some Dodd-Frank requirements to the extent they were to enter into swaps. However, at this time, management of the Utility Registrants continue to expect that their companies will not be materially affected by Dodd-Frank.

Generation s affiliation with the Utility Registrants, together with the presence of a substantial percentage of Generation s physical asset base within the Utility Registrants service territories, could increase Generation s cost of doing business to the extent future complaints or challenges regarding the Utility Registrants retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of the Utility Registrants and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation s affiliation with the Utility Registrants and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups could question or challenge costs and transactions incurred by the Utility Registrants with Generation, irrespective of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges could increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges could subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators could seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation-based taxes and contributions to rate-relief packages.

The Registrants could incur substantial costs to fulfill their obligations related to environmental and other matters. (All Registrants)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures including how they handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements could subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean-up costs, civil penalties and exposure to third parties claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean-up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and could be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the

retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029. On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance.

Additionally, Generation is subject to exposure for asbestos-related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos-related disease and exposure.

In some cases, a third-party who has acquired assets from a Registrant has assumed the liability the Registrant could otherwise have for environmental matters related to the transferred property. If the transferee is unable, or fails, to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant s remedies against the transferee could be limited by the financial resources of the transferee. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in the Utility Registrants respective terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which could introduce time delays in effectuating rate changes. (Exelon and the Utility Registrants)

The Utility Registrants are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for a Utility Registrant to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, the Utility Registrants could agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

The Utility Registrants cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland, the District of Columbia, Delaware, New Jersey or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that the Utility Registrants will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant default service obligations, referred to as POLR, DSP, SOS, and BGS, to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory

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rate proceedings have a significant effect on the ability of the Utility Registrants, as applicable, to recover their costs and could have a material adverse effect on the Utility Registrants results of operations, cash flows and financial position. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the results of operations or cash flows of Generation and the Utility Registrants. (All Registrants)

Changes to current state legislation or the development of Federal legislation that requires the use of renewable and alternate fuel sources, such as wind, solar, biomass and geothermal, could significantly impact Generation and the Utility Registrants, especially if timely cost recovery is not allowed for Utility Registrants. The impact could include increased costs for RECs and purchased power and increased rates for customers.

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact the Utility Registrants if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, Generation and the Utility Registrants. For additional information, see ITEM 1. BUSINESS Environmental Regulation-Renewable and Alternative Energy Portfolio Standards.

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon and the Utility Registrants. (Exelon and the Utility Registrants)

As of December 31, 2016, Exelon and the Utility Registrants have concluded that the operations of the Utility Registrants meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, and the Utility Registrants would be required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one-time charge in their Consolidated Statements of Operations and Comprehensive Income. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon and the Utility Registrants. At December 31, 2016, the gain (loss) could have been as much as $2.5 billion, $(1.1) billion, $(552) million, $(821) million, $(208) million and $(476) million (before taxes) as a result of the elimination of regulatory assets and liabilities of ComEd, PECO, BGE, Pepco, DPL and ACE, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.6 billion, $614 million, $424 million, $243 million, and $84 million for ComEd, BGE, Pepco, DPL and ACE respectively, related to Exelon s net regulatory assets associated with its defined benefit postretirement plans. Exelon also has a net regulatory liability of $47 million (before taxes) associated with PECO s defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an impairment of ComEd s or PHI s goodwill, which could be significant and at least partially offset the gains at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of the Utility Registrants to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1 Significant Accounting Policies, 3 Regulatory Matters and 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd s and PHI s goodwill, respectively.

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Exelon and Generation could incur material costs of compliance if Federal and/or state regulation or legislation is adopted to address climate change. (Exelon and Generation)

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions, and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation could incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. For example, more stringent permitting requirements could preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS Global Climate Change and Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards, including the likely exposure of the Utility Registrants to the results of PJM s RTEP and NERC compliance requirements. (All Registrants)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation and the Utility Registrants, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO, BGE, and DPL are also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards could subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU impose certain distribution reliability standards on the Utility Registrants. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards.

See Note 3 Regulatory Matters and Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants could be subject to adverse publicity and reputational risks, which make them vulnerable to negative customer perception and could lead to increased regulatory oversight or other consequences. (All Registrants)

The Registrants have large consumer customer bases and as a result could be the subject of public criticism focused on the operability of their assets and infrastructure and quality of their service. Adverse publicity of this nature could render legislatures and other governing bodies, public service commissions and other regulatory authorities, and government officials less likely to view energy companies such as Exelon and its subsidiaries in a favorable light, and could cause Exelon and its

subsidiaries to be susceptible to less favorable legislative and regulatory outcomes, as well as increased regulatory oversight and more stringent regulatory requirements. Unfavorable regulatory outcomes can include the enactment of more stringent laws and regulations governing Exelon s operations, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material negative impact on the Registrants business, results of operations, cash flows and financial positions.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could negatively impact their results of operations, cash flows or financial position. (All Registrants)

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants results of operations.

Generation could be negatively affected by possible Nuclear Regulatory Commission actions that could affect the operations and profitability of its nuclear generating fleet. (Exelon and Generation)

Regulatory risk. A change in the Atomic Energy Act or the applicable regulations or licenses could require a substantial increase in capital expenditures or could result in increased operating or decommissioning costs and significantly affect Generation s results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one previously considered at Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. The NRC s temporary storage rule (also referred to as the waste confidence decision) recognizes that licensees can safely store SNF at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants.

Any regulatory action relating to the timing and availability of a repository for SNF could adversely affect Generation s ability to decommission fully its nuclear units. Through May 15, 2014, in accordance with the NWPA and Generation s contract with the DOE, Generation paid the DOE a fee per kWh of net nuclear generation for the cost of SNF disposal. This fee was discontinued effective May 16, 2014. Until such time as a new fee structure is in effect, Exelon and Generation will not accrue any further costs related to SNF disposal fees. Generation currently estimates 2030 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF obligation. Generation cannot predict what, if any, fee will be established in the future for SNF disposal. However, such a fee could be material to Generation s results of operations or cash flows.

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Operational Factors

The Registrants employees, contractors, customers and the general public could be exposed to a risk of injury due to the nature of the energy industry. (All Registrants)

Employees and contractors throughout the organization work in, and customers and the general public could be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at some risk for serious injury, including loss of life. These risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events could negatively impact the Registrants results of operations, their ability to raise capital and their future growth. (All Registrants)

Generation s fleet of power plants and the Utility Registrants distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment.

Natural disasters and other significant events increase the risk to Generation that the NRC or other regulatory or legislative bodies could change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological matters. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation s continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general could adversely affect the Registrants operations and their ability to raise capital.

The impact that potential terrorist attacks could have on the industry in general and on Exelon in particular is uncertain. As owner-operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets or indirect casualties of an act of terror. Any retaliatory military strikes or sustained military campaign could affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Furthermore, these catastrophic events could compromise the physical or cyber security of Exelon s facilities, which could adversely affect Exelon s ability to manage its business effectively. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also could result in a decline in energy consumption, which could adversely affect the Registrants results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants could be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate Exelon s generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

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In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property and casualty losses subject to unforeseen occurrences or catastrophic events that could damage or destroy assets or interrupt operations. However, there can be no assurance that the amount of insurance will be adequate to address such property and casualty losses.

Generation s financial performance could be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors for generating units, particularly capacity factors for nuclear generating units, significantly affect Generation s results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation s operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation s obligations to committed third-party sales, including the Utility Registrants. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. In general, refueling outages are planned to occur once every 18 to 24 months. The total number of refueling outages, along with their duration, could have a significant impact on Generation s results of operations. When refueling outages last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

Nuclear fuel quality. The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation s operations. Certain of Generation s nuclear units have previously had a limited number of fuel performance issues. Remediation actions could result in increased costs due to accelerated fuel amortization, increased outage costs and/or increased costs due to decreased generation capabilities.

Operational risk. Operations at any of Generation s nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes could require significant time and expense. Generation could choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation could lose revenue and incur increased fuel and purchased power expense to meet supply commitments. For plants operated but not wholly owned by Generation, Generation could also incur liability to the co-owners. For plants not operated and not wholly owned by Generation, from which Generation receives a portion of the plants output, Generation s results of operations are dependent on the operational performance of the operators and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear-fueled energy, which could significantly affect Generation s results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could affect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident could be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned or operated by Generation or owned by others, could exceed Generation s resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the

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nuclear industry, could be borne by Generation and could have a material adverse effect on Generation s results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, whether owned Generation or others, could result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation s results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $450 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.4 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation s nuclear operations. In previous years, NEIL has made distributions to its members but Generation cannot predict the level of future distributions or if they will occur at all. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in certain minimum amounts at the end of the life of the facility to decommission the facility. Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired and units that are within five years of retirement) addressing Generation s ability to meet the NRC-estimated funding levels including scheduled contributions to and earnings on the decommissioning trust funds. The NRC funding levels are based upon the assumption that decommissioning will commence after the end of the current licensed life of each unit.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. The performance of capital markets also could significantly affect the value of the trust funds. Currently, Generation is making contributions to certain trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation, through PECO, has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from utility customers for any of its other nuclear units if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units could be negatively affected and Exelon s and Generation s results of operations or financial position could be significantly affected. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation s NDTs are not sufficient to fund the decommissioning of Generation s nuclear units, Generation could be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation s cash flows or financial position could be significantly adversely affected. Additionally, if the pledged assets are not sufficient to fund the Zion station decommissioning activities under the Asset Sale Agreement (ASA), Generation could have to seek remedies available under the ASA to reduce the risk of default by ZionSolutions and its parent. See Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

For nuclear units that are subject to regulatory agreements with either the ICC or the PAPUC, decommissioning-related activities are generally offset within Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd and PECO have recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability.

In the case of the nuclear units subject to the regulatory agreements with the ICC, if the funds held in the NDT funds for any former ComEd unit are expected to not exceed the total decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon s and Generation s results of operations and financial position could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and ComEd s noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation s Consolidated Statement of Operations and Comprehensive Income.

In the case of the nuclear units subject to the regulatory agreements with the PAPUC, any changes to the PECO regulatory agreements could impact Exelon s and Generation s ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon s and Generation s results of operations and financial position could be material. Additionally, any remaining balances in noncurrent payables to affiliates at Generation and PECO s noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact on Generation s Consolidated Statement of Operations and Comprehensive Income.

Generation s financial performance could be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Muddy Run Pumped Storage Project expires on December 1, 2055. The license for the Conowingo Hydroelectric Project expired September 1, 2014. FERC issued an annual license, effective as of the expiration of the previous license. If FERC does not issue a license prior to the expiration of the annual license, the annual license will renew automatically. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not issue new operating licenses for Generation s hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation s results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation could also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions could be imposed as part of the license renewal process that could adversely affect operations, could require a substantial increase in capital expenditures or could result in increased operating costs and significantly affect Generation s results of operations or financial position. Similar effects could result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

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The Registrants businesses are capital intensive, and their assets could require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (All Registrants)

The Registrants businesses are capital intensive and require significant investments by Generation in electric generating facilities and by the Utility Registrants in transmission and distribution infrastructure projects. These operational systems and infrastructure have been in service for many years. Equipment, even if maintained in accordance with good utility practices, is subject to operational failure, including events that are beyond the Registrants control, and could require significant expenditures to operate efficiently. The Registrants respective results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. Furthermore, operational failure of electric or gas systems or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for further information regarding the Registrants potential future capital expenditures.

The Utility Registrants operating costs, and customers and regulators opinions of the Utility Registrants are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon and the Utility Registrants)

Failures of the equipment or facilities, including information systems, used in the Utility Registrants delivery systems could interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in the Utility Registrants service territory fail to perform as intended or are not successfully integrated with billing and other information systems, the Utility Registrants results of operations, cash flows or financial condition could be negatively impacted. Furthermore, if any of the financial, accounting, or other data processing systems fail or have other significant shortcomings, the Utility Registrants financial results could be negatively impacted. If an employee causes the operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating the operational systems, the Utility Registrants financial results could also be negatively impacted. In addition, dependence upon automated systems could further increase the risk that operational system flaws or employee tampering or manipulation of those systems will result in losses that are difficult to detect.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, could affect customer satisfaction and the level of regulatory oversight and the Utility Registrants maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd could be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd s results of operations or cash flows. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd s service territory.

The Utility Registrants respective ability to deliver electricity, their operating costs and their capital expenditures could be negatively impacted by transmission congestion and failures of neighboring transmission systems. (All Registrants)

Demand for electricity within the Utility Registrants service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent

effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize the Utility Registrants ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring the Utility Registrant s to upgrade or expand their respective transmission systems through additional capital expenditures.

The electricity transmission facilities of the Utility Registrants are interconnected with the transmission facilities of neighboring utilities and are part of the interstate power transmission grid that is operated by PJM RTO. Although PJM s systems and operations are designed to ensure the reliable operation of the transmission grid and prevent the operations of one utility from having an adverse impact on the operations of the other utilities, there can be no assurance that service interruptions at other utilities will not cause interruptions in the Utility Registrants service areas. If the Utility Registrants were to suffer such a service interruption, it could have a negative impact on their and Exelon s results of operations, cash flows and financial position.

The Registrants are subject to physical security and cybersecurity risks. (All Registrants)

The Registrants face physical security and cybersecurity risks as the owner-operators of generation, transmission and distribution facilities and as participants in commodities trading. Threat sources continue to seek to exploit potential vulnerabilities in the electric and natural gas utility industry associated with protection of sensitive and confidential information, grid infrastructure and other energy infrastructures, and such attacks and disruptions, both physical and cyber, are becoming increasingly sophisticated and dynamic. Continued implementation of advanced digital technologies increase the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, interconnected entities in RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including critical infrastructure information, sensitive customer, vendor and employee data, trading or other confidential data. The risk of these system-related events and security breaches occurring continues to intensify, and while we have been, and will likely continue to be, subjected to physical and cyber-attacks, to date we have not experienced a material breach or disruption to our network or information systems or our service operations. However, as such attacks continue to increase in sophistication and frequency, the Registrants may be unable to prevent all such attacks in the future. If a significant breach were to occur, the reputation of Exelon and its customer supply activities could be adversely affected, customer confidence in the Registrants or others in the industry could be diminished, or Exelon and its subsidiaries could be subject to legal claims, any of which could contribute to the loss of customers and have a negative impact on the business and/or results of operations. Moreover, the amount and scope of insurance maintained against losses resulting from any such events or security breaches may not be sufficient to cover losses or otherwise adequately compensate for any disruptions to business that could result. The Utility Registrants deployment of smart meters throughout their service territories could increase the risk of damage from an intentional disruption of the system by third parties. In addition, new or updated security regulations or unforeseen threat sources could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

Failure to attract and retain an appropriately qualified workforce could negatively impact the Registrants results of operations. (All Registrants)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, could lead to operating challenges and

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increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, could arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively impacted.

The Registrants could make investments in new business initiatives, including initiatives mandated by regulators, and markets that may not be successful, and acquisitions could not achieve the intended financial results. (All Registrants)

Generation could continue to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain. This could include investment opportunities in renewables, development of natural gas generation, distributed generation, potential expansion of the existing wholesale gas businesses and entry into liquefied natural gas. Such initiatives could involve significant risks and uncertainties, including distraction of management from current operations, inadequate return on capital, and unidentified issues not discovered in the diligence performed prior to launching an initiative or entering a market. As these markets mature, there could be new market entrants or expansion by established competitors that increase competition for customers and resources. Additionally, it is possible that FERC, state public utility commissions or others could impose certain other restrictions on such transactions. All of these factors could result in higher costs or lower revenues than expected, resulting in lower than planned returns on investment.

The Utility Registrants face risks associated with their regulatory-mandated Smart Grid initiatives. These risks include, but are not limited to, cost recovery, regulatory concerns, cybersecurity and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on the Utility Registrants financial results.

Risks Related to the PHI Merger

The merger may not achieve its anticipated results, and Exelon could be unable to integrate the operations of PHI in the manner expected. (Exelon)

Exelon and PHI entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and PHI can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Exelon s businesses, processes and systems or inconsistencies in standards, controls, procedures, practices and policies, any of which could adversely affect the combined company s ability to achieve the anticipated benefits of the merger as and when expected. Exelon could 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 could cause dilution to Exelon s earnings per share, which could negatively affect the market price of Exelon s common stock. (Exelon)

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, could 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 could incur unexpected transaction fees and merger-related costs in connection with the merger. (Exelon, PHI, Pepco, DPL and ACE)

Exelon is incurring costs to combine the operations of Exelon, PHI and its subsidiaries. Exelon and PHI could incur additional unanticipated costs in the integration of the businesses of the two companies. Although Exelon and PHI expect 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 could encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the PHI Merger. (Exelon, PHI, Pepco, DPL and ACE)

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, one of which may remain subject to the most favored nation reconciliation process. It is possible that Exelon could 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, PHI s, Pepco s, DPL s and ACE s financial position and operating results.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

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ITEM 2. PROPERTIES
Generation

The following table describes Generation s interests in net electric generating capacity by station at December 31, 2016:

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,383
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,347
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,320
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,845
Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[(f)]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	82
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Beebe 1B	Midwest	Gratiot Co., MI	21		Wind	Base-load	50
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	20[(f)]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[(f)]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	9
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[(f)]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[(f)]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Solar Ohio	Midwest	Toledo, OH	3		Solar	Base-load	3
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Clinton Battery Storage	Midwest	Blanchester, OH	1		Energy Storage	Peaking	10
Total Midwest							12,150
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,301[(f)]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,005[(f)]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	879[(f)(g)]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[(e)]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Fourmile	Mid-Atlantic	Garrett County, MD	16		Wind	Base-load	40
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30

Solar Maryland MC	Mid-Atlantic	Various, MD	16	Solar	Base-load	28
Solar New Jersey 1	Mid-Atlantic	Various, NJ	6	Solar	Base-load	18
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1	Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2	Solar	Base-load	11
Solar Maryland	Mid-Atlantic	Various, MD	10	Solar	Base-load	9
Solar Maryland 2	Mid-Atlantic	Various, MD	3	Solar	Base-load	8
Solar Federal	Mid-Atlantic	Trenton, NJ	1	Solar	Base-load	5
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5	Solar	Base-load	2
Solar DC	Mid-Atlantic	District of Columbia	1	Solar	Base-load	1
Muddy Run	Mid-Atlantic	Drumore, PA	8	Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2	Oil/Gas	Intermediate	760
Perryman	Mid-Atlantic	Aberdeen, MD	5	Oil/Gas	Peaking	412
Croydon	Mid-Atlantic	West Bristol, PA	8	Oil	Peaking	391
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5	Gas	Peaking	268
Notch Cliff	Mid-Atlantic	Baltimore, MD	8	Gas	Peaking	117
Westport	Mid-Atlantic	Baltimore, MD	1	Gas	Peaking	116
Richmond	Mid-Atlantic	Philadelphia, PA	2	Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1	Gas	Peaking	97

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Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Riverside	Mid-Atlantic	Baltimore, MD	2		Oil/Gas	Peaking	39
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[(f)]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Total Mid-Atlantic							11,624
Whitetail	ERCOT	Webb County, TX	57		Wind	Base-load	91
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39		Wind	Base-load	78
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	705
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	568
Colorado Bend	ERCOT	Wharton, TX	6		Gas	Intermediate	468
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							3,567
Solar Massachusetts	New England	Various, MA	11		Solar	Base-load	5
Holyoke Solar	New England	Various, MA	2		Solar	Base-load	5
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various, CT	3		Solar	Base-load	2
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,415
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36[(f)]
West Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	124
Framingham	New England	Framingham, MA	3		Oil	Peaking	31
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,204
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838[(f)(g)]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[(f)(g)]
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	3

Total New York							1,129
AVSR	Other	Lancaster, CA	1		Solar	Base-load	242
Shooting Star	Other	Kiowa County, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluestem	Other	Beaver County, OK	60	29	Wind	Base-load	57
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Solar Arizona	Other	Various, AZ	127		Solar	Base-load	46
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	34[f]
Sacramento PV Energy	Other	Sacramento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27
Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f][h]
Solar Arizona 2	Other	Various, AZ	25		Solar	Base-load	23

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Station (a)	Region	Location	No. of Units	Percent Owned (b)	Primary Fuel Type	Primary Dispatch Type (c)	Net Generation Capacity (MW) (d)
California PV Energy	Other	Various, CA	53		Solar	Base-load	21
Echo 2	Other	Echo, OR	10		Wind	Base-load	20
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10(f)
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10(i)
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10(i)
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10(i)
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10(f)
Three Mile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
California PV Energy 2	Other	Various, CA	31		Solar	Base-load	9
Solar Georgia	Other	Various, GA	10		Solar	Base-load	8
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Mohave Sunrise Solar	Other	Fort Mohave, AZ	1		Solar	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
Solar California	Other	Various, CA	4		Solar	Base-load	3
Solar Georgia 2	Other	Various, GA	1		Solar	Base-load	1
Hillabee	Other	Alexander City, AL	3		Gas	Intermediate	753
Grande Prairie	Other	Alberta, Canada	1		Gas	Peaking	105
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	9(f)
Total Other							2,046
Total							32,720

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by November 30, 2019.

(f) Net generation capacity is stated at proportionate ownership share.
(g) Reflects Generation s 50.01% interest in CENG, a joint venture with EDF. For Nine Mile Point, the co-owner owns 18% of Unit 2. Thus Exelon s ownership is 50.01% of 82% of Nine Mile Point Unit 2.
(h) Generation sold its 50% interest in Sunnyside effective February 3, 2017
(i) Generation plans to retire and cease generation operations at the Exelon Wind 1, Exelon Wind 2 and Exelon Wind 3 units effective June 1, 2017.

The net generation capability available for operation at any time may be less due to regulatory restrictions, transmission congestion, fuel restrictions, efficiency of cooling facilities, level of water supplies or generating units being temporarily out of service for inspection, maintenance, refueling, repairs or modifications required by regulatory authorities.

Generation maintains property insurance against loss or damage to its principal plants and properties by fire or other perils, subject to certain exceptions. For additional information regarding nuclear insurance of generating facilities, see ITEM 1. BUSINESS Exelon Generation Company, LLC. For its insured losses, Generation is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on Generation s consolidated financial condition or results of operations.

ComEd

ComEd s electric substations and a portion of its transmission rights of way are located on property that ComEd owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ComEd believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements, licenses and franchise rights; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ComEd s higher voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,658
138,000	2,208

ComEd s electric distribution system includes 35,397 circuit miles of overhead lines and 31,049 circuit miles of underground lines.

First Mortgage and Insurance

The principal properties of ComEd are subject to the lien of ComEd s Mortgage dated July 1, 1923, as amended and supplemented, under which ComEd s First Mortgage Bonds are issued.

ComEd maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ComEd is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ComEd.

PECO

PECO s electric substations and a significant portion of its transmission lines are located on property that PECO owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. PECO believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

PECO s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188 [a]
230,000	549

138,000	156
69,000	200

(a) In addition, PECO has a 22.00% ownership interest in 127 miles of 500 kV lines located in Pennsylvania and a 42.55% ownership interest in 131 miles of 500 kV lines located in Delaware and New Jersey.

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PECO s electric distribution system includes 12,963 circuit miles of overhead lines and 9,290 circuit miles of underground lines.

Gas

The following table sets forth PECO s natural gas pipeline miles at December 31, 2016:

	Pipeline Miles
Transmission	30
Distribution	6,871
Service piping	6,273
Total	13,174

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 150 mmcf and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

The principal properties of PECO are subject to the lien of PECO s Mortgage dated May 1, 1923, as amended and supplemented, under which PECO s first and refunding mortgage bonds are issued.

PECO maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, PECO is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of PECO.

BGE

BGE s electric substations and a significant portion of its transmission lines are located on property that BGE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. BGE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

BGE s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	331

138,000	55
115,000	709

BGE s electric distribution system includes 9,443 circuit miles of overhead lines and 17,306 circuit miles of underground lines.

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Gas

The following table sets forth BGE s natural gas pipeline miles at December 31, 2016:

	Pipeline Miles
Transmission	161
Distribution	7,239
Service piping	6,230
Total	13,630

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,056 mmcf and a send-out capacity of 332 mmcf/day and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 550 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

BGE owns its principal headquarters building located in downtown Baltimore. BGE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, BGE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of BGE.

Pepco

Pepco s electric substations and a significant portion of its transmission lines are located on property that Pepco owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. Pepco believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

Pepco s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	142
230,000	774
138,000	60
115,000	38

Pepco s electric distribution system includes approximately 4,100 circuit miles of overhead lines and 6,800 circuit miles of underground lines. Pepco also operates a distribution system control center in Bethesda, Maryland. The computer equipment and systems contained in Pepco s control center are financed through a sale and leaseback transaction.

First Mortgage and Insurance

The principal properties of Pepco are subject to the lien of Pepco s mortgage dated July 1, 1935, as amended and supplemented, under which Pepco First Mortgage Bonds are issued.

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Pepco maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, Pepco is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of Pepco.

DPL

DPL s electric substations and a significant portion of its transmission lines are located on property that DPL owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. DPL believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

DPL s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	16
230,000	470
138,000	557
69,000	576

DPL s electric distribution system includes approximately 6,100 circuit miles of overhead lines and 6,100 circuit miles of underground lines. DPL also owns and operates a distribution system control center in New Castle, Delaware.

Gas

The following table sets forth DPL s natural gas pipeline miles at December 31, 2016 :

	Pipeline Miles
Transmission [(a)]	7
Distribution	2,036
Service Piping	1,385
Total	3,428

(a) DPL has a 10% undivided interest in approximately 7 miles of natural gas transmission mains located in Delaware which are used by DPL for its natural gas operations and by 90% owner for distribution of natural gas to its electric generating facilities.

DPL owns a liquefied natural gas facility located in Wilmington, Delaware, with a storage capacity of approximately 3,045 mmcf and an emergency sendout capability of 36,000 Mcf per day. DPL owns 4 natural gas city gate stations at various locations in New Castle County, Delaware. These stations have a total primary delivery point contractual entitlement of 158,485 Mcf per day.

First Mortgage and Insurance

The principal properties of PDL are subject to the lien of DPL s mortgage dated October 1, 1947, as amended and supplemented, under which DPL First Mortgage Bonds are issued.

DPL maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, DPL is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of DPL.

ACE

ACE s electric substations and a significant portion of its transmission lines are located on property that ACE owns. A significant portion of its electric transmission and distribution facilities is located above or underneath highways, streets, other public places or property that others own. ACE believes that it has satisfactory rights to use those places or property in the form of permits, grants, easements and licenses; however, it has not necessarily undertaken to examine the underlying title to the land upon which the rights rest.

Transmission and Distribution

ACE s high voltage electric transmission lines owned and in service at December 31, 2016 were as follows:

Voltage (Volts)	Circuit Miles
500,000	281
230,000	234
138,000	268
69,000	652

ACE s electric distribution system includes approximately 7,400 circuit miles of overhead lines and 2,900 circuit miles of underground lines. ACE also owns and operates a distribution system control center in Mays Landing, New Jersey.

First Mortgage and Insurance

The principal properties of ACE are subject to the lien of ACE s mortgage dated January 15, 1937, as amended and supplemented, under which ACE First Mortgage Bonds are issued.

ACE maintains property insurance against loss or damage to its properties by fire or other perils, subject to certain exceptions. For its insured losses, ACE is self-insured to the extent that any losses are within the policy deductible or exceed the amount of insurance maintained. Any such losses could have a material adverse effect on the consolidated financial condition or results of operations of ACE.

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long-term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country s energy systems.

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ITEM 3. LEGAL PROCEEDINGS
All Registrants

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 Note 3 Regulatory Matters and Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES
All Registrants

Not Applicable to the Registrants.

PART II

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

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon

Exelon s common stock is listed on the New York Stock Exchange. As of January 31, 2017, there were 926,589,614 shares of common stock outstanding and approximately 113,308 record holders of common stock.

The following table presents the New York Stock Exchange Composite Common Stock Prices and dividends by quarter on a per share basis:

	2016				2015			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 36.36	$ 37.70	$ 36.37	$ 35.95	$ 31.37	$ 34.44	$ 34.98	$ 38.25
Low price	29.82	32.86	33.18	26.26	25.09	28.41	31.28	31.71
Close	35.49	33.29	36.36	35.86	27.77	29.70	31.42	33.61
Dividends	0.318	0.318	0.318	0.310	0.310	0.310	0.310	0.310

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Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index, for the period 2012 through 2016.

This performance chart assumes:

$100 invested on December 31, 2011 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and

All dividends are reinvested.

	Value of Investment at December 31,					
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
Exelon Corporation	$100	$70.69	$65.11	$88.14	$66.01	$84.36
S&P 500	$100	$111.68	$144.74	$161.22	$160.05	$175.31
S&P Utilities	$100	$98.78	$107.43	$133.52	$122.32	$137.24

Generation

As of January 31, 2017, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2017, there were 127,017,157 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2017, in addition to Exelon, there were 299 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2017, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2017, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

PHI

As of January 31, 2017, Exelon indirectly held the entire membership interest in PHI.

Pepco

As of January 31, 2017, there were 100 outstanding shares of common stock, $0.01 par value, of Pepco, all of which were indirectly held by Exelon.

DPL

As of January 31, 2017, there were 1,000 outstanding shares of common stock, $2.25 par value, of DPL, all of which were indirectly held by Exelon.

ACE

As of January 31, 2017, there were 8,546,017 outstanding shares of common stock, $3.00 par value, of ACE, all of which were indirectly held by Exelon.

All Registrants

Dividends

Under applicable Federal law, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd, PECO, BGE, PHI, Pepco, DPL or ACE may limit the dividends that these companies can distribute to Exelon.

The Federal Power Act declares it to be unlawful for any officer or director of any public utility to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account. What constitutes funds properly included in capital account is undefined in the Federal Power Act or the related regulations; however, FERC has consistently interpreted the provision to allow dividends to be paid as long as (1) the source of the dividends is clearly disclosed, (2) the dividend is not excessive and (3) there is no self-dealing on the part of corporate officials. While these restrictions may limit the absolute amount of dividends that a particular subsidiary may pay, Exelon does not believe these limitations are materially limiting because, under these limitations, the subsidiaries are allowed to pay dividends sufficient to meet Exelon s actual cash needs.

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, [its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves, or unless it has specific authorization from the ICC. ComEd has also agreed in connection with a financing arranged through ComEd Financing III that ComEd will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued. No such event has occurred.

PECO has agreed in connection with financings arranged through PEC L.P. and PECO Trust IV that PECO will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued. No such event has occurred.

BGE is subject to certain dividend restrictions established by the MDPSC. First, in connection with the Constellation merger, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid and notify the MDPSC that BGE s equity ratio is at least 48% within five business days after dividend payment. There are no other limitations on BGE paying common stock dividends unless BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid.

Pepco is subject to certain dividend restrictions limits imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of future preferred stock, if any, and existing and future mortgage bonds and other long-term debt issued by Pepco and any other restrictions imposed in connection with the incurrence of liabilities.

DPL is subject to certain dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends, and (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by DPL and any other restrictions imposed in connection with the incurrence of liabilities.

ACE is subject to dividend restrictions imposed by: (i) state corporate laws, which impose limitations on the funds that can be used to pay dividends and the regulatory requirement that ACE obtain the prior approval of the NJBPU before dividends can be paid if its equity as a percent of its total capitalization, excluding securitization debt, falls below 30%; (ii) the prior rights of holders of existing and future preferred stock, mortgage bonds and other long-term debt issued by ACE and any other restrictions imposed in connection with the incurrence of liabilities; and (iii) certain provisions of the charter of ACE which impose restrictions on payment of common stock dividends for the benefit of preferred stockholders. Currently, the restriction in the ACE charter does not limit its ability to pay common stock dividends.

Exelon s Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

At December 31, 2016, Exelon had retained earnings of $12,030 million, including Generation s undistributed earnings of $2,275 million, ComEd s retained earnings of $987 million consisting of retained earnings appropriated for future dividends of $2,626 million, partially offset by $(1,639) million of unappropriated accumulated deficits, PECO s retained earnings of $941 million, BGE s retained earnings of $1,427 million, and PHI s undistributed earnings of $(61)

million.

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The following table sets forth Exelon s quarterly cash dividends per share paid during 2016 and 2015:

	2016				2015			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.318	$ 0.318	$ 0.318	$ 0.310	$ 0.310	$ 0.310	$ 0.310	$ 0.310

The following table sets forth Generation s and PHI s quarterly distributions and ComEd s, PECO s, Pepco s, DPL s and ACE s quarterly common dividend payments:

	2016				2015			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 755	$ 56	$ 56	$ 55	$ 106	$ 106	$ 906	$ 1,356
ComEd	94	92	92	91	73	76	75	75
PECO	69	69	70	69	70	70	69	70
BGE	45	44	45	45	42	39	41	36
PHI	99	50	16	108	69	69	69	68
Pepco	44	37	16	39	55	60	31	
DPL	15	1		38	12	18		62
ACE	39	13		11				12

First Quarter 2017 Dividend. On January 31, 2017, the Exelon Board of Directors declared a first quarter 2017 regular quarterly dividend of $0.3275 per share on Exelon s common stock payable on March 10, 2017, to shareholders of record of Exelon at the end of the day on February 15, 2017.

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ITEM 6. SELECTED FINANCIAL DATA
Exelon

The selected financial data presented below has been derived from the audited consolidated financial statements of Exelon. This data is qualified in its entirety by reference to and should be read in conjunction with Exelon s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions, except per share data)	**2016** [(a)]	**2015**	**2014** [(b)]	**2013**	**2012** [(c)]
Statement of Operations data:					
Operating revenues	$ 31,360	$ 29,447	$ 27,429	$ 24,888	$ 23,489
Operating income	3,112	4,409	3,096	3,669	2,373
Net income	1,204	2,250	1,820	1,729	1,171
Net income attributable to common shareholders	1,134	2,269	1,623	1,719	1,160
Earnings per average common share (diluted):					
Net income	$ 1.22	$ 2.54	$ 1.88	$ 2.00	$ 1.42
Dividends per common share	$ 1.26	$ 1.24	$ 1.24	$ 1.46	$ 2.10

(a) The 2016 financial results include the activity of PHI from the merger effective date of March 24, 2016 through December 31, 2016.
(b) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis.
(c) The 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

	December 31,				
(In millions)	**2016**	**2015**	**2014**	**2013**	**2012**
Balance Sheet data:					
Current assets	$ 12,412	$ 15,334	$ 11,853	$ 9,562	$ 10,009
Property, plant and equipment, net	71,555	57,439	52,170	47,330	45,186
Total assets	114,904	95,384	86,416	79,243	78,350
Current liabilities	13,457	9,118	8,762	7,686	7,734
Long-term debt, including long-term debt to financing trusts	32,216	24,286	19,853	18,165	18,266
Preferred securities of subsidiary					87
Shareholders equity	25,837	25,793	22,608	22,732	21,431

Generation

The selected financial data presented below has been derived from the audited consolidated financial statements of Generation. This data is qualified in its entirety by reference to and should be read in conjunction with Generation s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF

FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,				
(In millions)	**2016**	**2015**	**2014 (a)**	**2013**	**2012 (b)**
Statement of Operations data:					
Operating revenues	$ 17,751	$ 19,135	$ 17,393	$ 15,630	$ 14,437
Operating income	836	2,275	1,176	1,677	1,113
Net income	558	1,340	1,019	1,060	558

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s results of operations on a fully consolidated basis.

(b) The 2012 financial results include the activity of Constellation from the merger effective date of March 12, 2012 through December 31, 2012.

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(In millions)	2016	2015	December 31, 2014	2013	2012
Balance Sheet data:					
Current assets	$ 6,528	$ 6,342	$ 7,311	$ 5,964	$ 6,211
Property, plant and equipment, net	25,585	25,843	23,028	20,111	19,531
Total assets	46,974	46,529	44,951	40,700	40,648
Current liabilities	5,683	4,933	4,459	3,842	3,969
Long-term debt, including long-term debt to affiliate	8,124	8,869	7,582	7,111	7,422
Member s equity	11,482	11,635	12,718	12,725	12,557

ComEd

The selected financial data presented below has been derived from the audited consolidated financial statements of ComEd. This data is qualified in its entirety by reference to and should be read in conjunction with ComEd s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	2016	2015	For the Years Ended December 31, 2014	2013	2012
Statement of Operations data:					
Operating revenues	$ 5,254	$ 4,905	$ 4,564	$ 4,464	$ 5,443
Operating income	1,205	1,017	980	954	886
Net income	378	426	408	249	379

(In millions)	2016	2015	December 31, 2014	2013	2012
Balance Sheet data:					
Current assets	$ 1,554	$ 1,518	$ 1,723	$ 1,540	$ 1,692
Property, plant and equipment, net	19,335	17,502	15,793	14,666	13,826
Total assets	28,335	26,532	25,358	24,089	22,793
Current liabilities	2,938	2,766	1,923	2,032	1,655
Long-term debt, including long-term debt to financing trusts	6,813	6,049	5,870	5,235	5,492
Shareholders equity	8,725	8,243	7,907	7,528	7,323

PECO

The selected financial data presented below has been derived from the audited consolidated financial statements of PECO. This data is qualified in its entirety by reference to and should be read in conjunction with PECO s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	2016	2015	For the Years Ended December 31, 2014	2013	2012
Statement of Operations data:					

Operating revenues	$ 2,994	$ 3,032	$ 3,094	$ 3,100	$ 3,186
Operating income	702	630	572	666	623
Net income	438	378	352	395	381

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(In millions)	2016	2015	December 31, 2014	2013	2012
Balance Sheet data:					
Current assets	$ 757	$ 842	$ 645	$ 821	$ 1,054
Property, plant and equipment, net	7,565	7,141	6,801	6,384	6,078
Total assets	10,831	10,367	9,860	9,521	9,303
Current liabilities	727	944	653	889	1,158
Long-term debt, including long-term debt to financing trusts	2,764	2,464	2,416	2,120	1,821
Preferred securities					87
Shareholders equity	3,415	3,236	3,121	3,065	2,982

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	2016	2015	For the Years Ended December 31, 2014	2013	2012
Statement of Operations data:					
Operating revenues	$ 3,233	$ 3,135	$ 3,165	$ 3,065	$ 2,735
Operating income	550	558	439	449	132
Net income	294	288	211	210	4

(In millions)	2016	2015	December 31, 2014	2013	2012
Balance Sheet data:					
Current assets	$ 842	$ 845	$ 951	$ 1,009	$ 979
Property, plant and equipment, net	7,040	6,597	6,204	5,864	5,498
Total assets	8,704	8,295	8,056	7,839	7,485
Current liabilities	707	1,134	794	800	980
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,533	1,732	2,109	2,179	1,949
Shareholders equity	2,848	2,687	2,563	2,365	2,168

PHI

The selected financial data presented below has been derived from the audited consolidated financial statements of PHI. This data is qualified in its entirety by reference to and should be read in conjunction with PHI s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

Successor *Predecessor*

(In millions)	March 24 - December 31 2016	January 1 - March 23 2016	For the Years Ended December 31, 2015	2014
Statement of Operations data [a]:				
Operating revenues	$ 3,643	$ 1,153	$ 4,935	$ 4,808
Operating income	93	105	673	605
Net (loss) income from continuing operations	(61)	19	318	242
Net (loss) income	(61)	19	327	242

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(In millions)	*Successor* December 31, 2016	*Predecessor* December 31, 2015
Balance Sheet data [(a)]:		
Current assets	$ 1,838	$ 1,474
Property, plant and equipment, net	11,598	10,864
Total assets	21,025	16,188
Current liabilities	2,284	2,327
Long-term debt	5,645	4,823
Preferred Stock		183
Member s equity/Shareholders equity	8,016	4,413

(a) As a result of the PHI Merger in 2016, Exelon has elected to present PHI s selected financial data for the periods reflected above.

Pepco

The selected financial data presented below has been derived from the audited consolidated financial statements of Pepco. This data is qualified in its entirety by reference to and should be read in conjunction with Pepco s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data [(a)]:			
Operating revenues	$ 2,186	$ 2,129	$ 2,055
Operating income	174	385	349
Net (loss) income	42	187	171

(In millions)	December 31, 2016	2015
Balance Sheet data [(a)]:		
Current assets	$ 684	$ 726
Property, plant and equipment, net	5,571	5,162
Total assets	7,335	6,908
Current liabilities	596	455
Long-term debt	2,333	2,340
Shareholders equity	2,300	2,240

(a) As a result of the PHI Merger in 2016, Exelon has elected to present Pepco s selected financial data for the periods reflected above.

DPL

The selected financial data presented below has been derived from the audited consolidated financial statements of DPL. This data is qualified in its entirety by reference to and should be read in conjunction with DPL s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

	For the Years Ended December 31,		
(In millions)	**2016**	**2015**	**2014**
Statement of Operations data [(a)]:			
Operating revenues	$ 1,277	$ 1,302	$ 1,282
Operating income	50	165	207
Net (loss) income	(9)	76	104

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(In millions)	December 31, 2016	2015
Balance Sheet data [(a)]:		
Current assets	$ 370	$ 388
Property, plant and equipment, net	3,273	3,070
Total assets	4,153	3,969
Current liabilities	381	564
Long-term debt	1,221	1,061
Shareholders equity	1,326	1,237

(a) As a result of the PHI Merger in 2016, Exelon has elected to present DPL s selected financial data for the periods reflected above.

ACE

The selected financial data presented below has been derived from the audited consolidated financial statements of ACE. This data is qualified in its entirety by reference to and should be read in conjunction with ACE s Consolidated Financial Statements and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

(In millions)	For the Years Ended December 31, 2016	2015	2014
Statement of Operations data [(a)]:			
Operating revenues	$ 1,257	$ 1,295	$ 1,210
Operating income	7	134	137
Net (loss) income	(42)	40	46

(In millions)	December 31, 2016	2015
Balance Sheet data [(a)]:		
Current assets	$ 399	$ 546
Property, plant and equipment, net	2,521	2,322
Total assets	3,457	3,387
Current liabilities	320	297
Long-term debt	1,120	1,153
Shareholders equity	1,034	1,000

(a) As a result of the PHI Merger in 2016, Exelon has elected to present ACE s selected financial data for the periods reflected above.

Item 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Exelon

Executive Overview

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

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

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

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

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

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

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

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

Pepco, DPL and ACE are operating companies of PHI, which is a utility services holding company and a wholly owned subsidiary of Exelon.

Exelon has twelve reportable segments consisting of Generation s six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO, BGE and PHI s three utility reportable segments (Pepco, DPL and ACE). See Note 26 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.

PHI Service Company, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

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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.

Financial Results of Operations

GAAP Results of Operations

The following tables set forth Exelon s GAAP consolidated results of operations for the year ended December 31, 2016 compared to the same period in 2015. 2016 amounts include the operations of PHI, Pepco, DPL and ACE from March 24, 2016 through December 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	For the Years Ended December 31, 2016								Favorable
								2015	(Unfavorable)
	Generation	ComEd	PECO	BGE	PHI[(b)]	Other	Exelon	Exelon	Variance
Operating revenues	$ 17,751	$ 5,254	$ 2,994	$ 3,233	$ 3,643	$ (1,515)	$ 31,360	$ 29,447	$ 1,913
Purchased power and fuel expense	8,830	1,458	1,047	1,294	1,447	(1,436)	12,640	13,084	444
Revenue net of purchased power and fuel expense [(a)]	8,921	3,796	1,947	1,939	2,196	(79)	18,720	16,363	2,357
Other operating expenses									
Operating and maintenance	5,641	1,530	811	737	1,233	96	10,048	8,322	(1,726)
Depreciation and amortization	1,879	775	270	423	515	74	3,936	2,450	(1,486)
Taxes other than income	506	293	164	229	354	30	1,576	1,200	(376)
Total other operating expenses	8,026	2,598	1,245	1,389	2,102	200	15,560	11,972	(3,588)
Gain (Loss) on sales of assets	(59)	7			(1)	5	(48)	18	(66)
Operating income (loss)	836	1,205	702	550	93	(274)	3,112	4,409	(1,297)
Other income and (deductions)									

Interest expense, net	(364)	(461)	(123)	(103)	(195)	(290)	(1,536)	(1,033)	(503)
Other, net	401	(65)	8	21	44	4	413	(46)	459
Total other income and (deductions)	37	(526)	(115)	(82)	(151)	(286)	(1,123)	(1,079)	(44)
Income (loss) before income taxes	873	679	587	468	(58)	(560)	1,989	3,330	(1,341)
Income taxes	290	301	149	174	3	(156)	761	1,073	312
Equity in (losses) earnings of unconsolidated affiliates	(25)					1	(24)	(7)	(17)
Net income (loss)	558	378	438	294	(61)	(403)	1,204	2,250	(1,046)
Net income (loss) attributable to noncontrolling interests and preference stock dividends	62			8			70	(19)	89
Net income (loss) attributable to common shareholders	$ 496	$ 378	$ 438	$ 286	$ (61)	$ (403)	$ 1,134	$ 2,269	$ (1,135)

(a) The Registrants evaluate operating performance using the measure of revenues net of purchased power and fuel expense. The Registrants believe that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel

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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 December 31, 2016.

Exelon s net income attributable to common shareholders was $1,134 million for the year ended December 31, 2016 as compared to $2,269 million for the year ended December 31, 2015, and diluted earnings per average common share were $1.22 for the year ended December 31, 2016 as compared to $2.54 for the year ended December 31, 2015.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $2,357 million as compared to 2015. The year-over-year increase was primarily due to the following favorable factors:

- Increase of $2,196 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 December 31, 2016;

- Increase of $210 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 $109 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 increased rates as a result of the distribution rate orders issued by the MDPSC in June 2016 and July 2016;

- Increase of $105 million at Generation primarily due to the impact of the Ginna Reliability Support Services Agreement and a decrease in nuclear outage days at higher capacity units despite an increase in overall outage days, partially offset by lower realized energy prices; and

- Increase of $105 million at PECO primarily due to increased electric distribution revenue pursuant to a rate increase effective January 1, 2016.

The year-over-year increase in operating revenues net of purchased power and fuel expense described above was partially offset by a decrease of $298 million at Generation due to mark-to-market losses of $41 million in 2016 from economic hedging activities as compared to gains of $257 million in 2015.

Operating and maintenance expense increased by $1,726 million as compared to 2015. The year-over-year increase was primarily due to the following unfavorable factors:

- Increase of $910 million, exclusive of merger commitment costs discussed above, due to the inclusion of PHI s results for the period March 24, 2016 to December 31, 2016;

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;

Increase in Generation s labor, contracting and materials cost of $185 million related to the inclusion of Pepco Energy Services results in 2016 and increased contracting costs related to energy efficiency projects;

Long-lived asset impairments of $171 million at Generation in 2016 compared to $10 million in 2015;

Increase of $54 million at BGE primarily as a result of one-time charges associated with the reduction of regulatory assets and other long-lived assets stemming from certain cost disallowances contained within the distribution rate orders issued by the MDPSC in June and July 2016; and

Increase of $28 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.

The year-over-year increase in operating and maintenance expense was partially offset by the following favorable factors:

Decrease of $79 million at Generation as a result of the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units in 2016 versus 2015;

Decrease of $79 million at Generation as a result of a decrease in nuclear outage days in 2016, excluding Salem; and

Decrease of $77 million in pension and non-pension post-retirement benefit costs resulting from the favorable impact of higher pension and OPEB discount rates in 2016.

Depreciation and amortization expense increased by $1,486 million primarily as a result of accelerated depreciation and amortization expense related to Generation s previous 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 December 31, 2016.

Taxes other than income increased $376 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 December 31, 2016.

Gain (Loss) on sales of assets decreased $66 million primarily due to certain Generation projects and contracts being terminated or renegotiated in 2016, partially offset by a gain associated with Generation s sale of the retired New Boston generating site in 2016.

Interest expense, net increased by $503 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 $459 million primarily due to the change in realized and unrealized gains and losses on NDT funds at Generation, partially offset by the recognition of the penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position.

Exelon s effective income tax rates for the years ended December 31, 2016 and 2015 were 38.3% and 32.2%, respectively. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates. Exelon recorded an after-tax charge of $98 million for the year ended December 31, 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 years ended December 31, 2016 and 2015, including explanation of the non-GAAP measure revenues net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

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Adjusted (non-GAAP) Operating Earnings

Exelon s adjusted (non-GAAP) operating earnings for the year ended December 31, 2016 were $2,488 million, or $2.68 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,227 million, or $2.49 per diluted share, for the same period in 2015. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor s overall understanding of year-to-year operating results and provide an indication of Exelon s baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

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 year ended December 31, 2016 as compared to 2015:

	For the years ended December 31,			
	2016		2015	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income Attributable to Common Shareholders	$ 1,134	$ 1.22	$ 2,269	$ 2.54
Mark-to-Market Impact of Economic Hedging Activities [a]	24	0.03	(158)	(0.18)
Unrealized (Gains) Losses Related to NDT Fund Investments [b]	(118)	(0.13)	115	0.13
Plant Retirements and Divestitures [c]	432	0.47		
Asset Retirement Obligation [d]	(75)	(0.08)	(6)	(0.01)
Merger and Integration Costs [e]	114	0.12	58	0.07
Amortization of Commodity Contract Intangibles [f]	35	0.04	(5)	
Reassessment of State Deferred Income Taxes [g]	10	0.01	41	0.05
Long-Lived Asset Impairments [h]	103	0.11	21	0.02
Tax Settlements [i]			(52)	(0.06)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps [j]			(21)	(0.02)
PHI Merger Related Redeemable Debt Exchange [k]			13	0.01
Reduction in State Income Tax Reserve [l]			(10)	(0.01)
Midwest Generation Bankruptcy Recoveries [m]			(6)	(0.01)
Merger Commitments [n]	437	0.47		
Curtailment of Generation Growth and Development Activities [o]	57	0.06		
Cost Management Program [p]	34	0.04		
Like-Kind Exchange Tax Position [q]	199	0.21		
CENG Noncontrolling Interests [r]	102	0.11	(32)	(0.04)

Adjusted (non-GAAP) Operating Earnings	$ 2,488	$ 2.68	$ 2,227	$ 2.49

(a) Reflects the impact of (gains) losses for the years ended December 31, 2016 and 2015 (net of taxes of $18 million and $99 million, respectively) on Generation s economic hedging activities. See Note 13 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 unrealized (gains) losses for the years ended December 31, 2016 and 2015 (net of taxes of $112 million and $148 million, respectively) on Generation s NDT fund investments for Non-Regulatory Agreement Units.

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See Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s NDT fund investments.

(c) Primarily reflects incremental accelerated depreciation and amortization expenses from June 2, 2016 through December 6, 2016 and construction work in progress impairments pursuant to the second quarter decision to early retire the Clinton and Quad Cities nuclear generating facilities, which decision was reversed in December 2016 (net of taxes of $285 million), partially offset by a gain associated with Generation s 2016 sale of the New Boston generating site (net of taxes of $12 million).

(d) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the Non-Regulatory Agreement Units for the years ended December 31, 2016 and 2015 (net of taxes of $13 million and $4 million, respectively).

(e) Reflects certain costs associated with mergers and acquisitions incurred for the years ended December 31, 2016 and 2015 (net of taxes of $50 million and $38 million, respectively) including professional fees, employee-related expenses, integration activities and upfront credit facilities fees related to the PHI acquisition and pending Fitzpatrick acquisition, partially offset in 2016 at ComEd, BGE and PHI by the anticipated recovery of previously incurred PHI acquisition costs.

(f) Reflects the non-cash impact for the years ended December 31, 2016 and 2015 (net of taxes of $22 million and $3 million, respectively) of the amortization of commodity contracts recorded at fair value associated with prior acquisitions, if and when applicable.

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment.

(h) Reflects impairment of upstream assets and certain wind projects in 2016 (net of taxes of $68 million) and the impairment of investment in long-term leases at Corporate in 2015 (net of taxes of $13 million).

(i) Reflects a benefit related to the favorable settlement in 2015 of certain income tax positions on Constellation s pre-acquisition tax returns.

(j) Reflects the impact of mark-to-market activity on forward-starting interest rate swaps held at Exelon Corporate related to financing for the PHI acquisition for the year ended December 31, 2015 (net of taxes of $14 million).

(k) Reflects the costs associated with the exchange and redemption in December 2015 of certain mandatorily redeemable debt issued to finance the PHI merger (net of taxes of $8 million in 2015).

(l) Reflects the reduction of a previously recorded state income tax reserve associated with the 2014 sales of Keystone and Conemaugh for the year ended December 31, 2015.

(m) Reflects a benefit for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy for the year ended December 31, 2015 (net of taxes of $4 million).

(n) Represents adjustments to costs incurred as part of the settlement orders approving the PHI acquisition and a charge related to a 2012 CEG merger commitment for the year ended December 31, 2016 (net of taxes of $126 million).

(o) Reflects the one-time recognition for a loss on sale of assets and asset impairment charges pursuant to Generation s strategic decision to narrow the scope and scale of its growth and development activities for the year ended December 31, 2016 (net of taxes of $35 million).

(p) Represents 2016 severance expense and reorganization costs related to a cost management program (net of taxes of $21 million).

(q) Represents 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 (net of taxes of $61 million).

(r) Represents elimination from Generation s results of the noncontrolling interests related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments and changes in asset retirement obligations in 2016, and in 2015 the impact of unrealized gains and losses on NDT fund investments and mark-to-market activity.

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.

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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.

	For the Year Ended December 31, 2016					*Successor* March 24, 2016 to December 31, 2016
	Exelon	**Generation**	**Pepco**	**DPL**	**ACE**	**PHI**
Merger commitments	$ 513	$ 3	$ 126	$ 86	$ 111	$ 323
Changes in accounting and tax related policies and estimates			25	15	5	
Total	$ 513	$ 3	$ 151	$ 101	$ 116	$ 323

In addition to the one-time PHI Merger charges discussed above, for the years ended December 31, 2016 and 2015, expense has been recognized for the PHI Merger, Constellation acquisition and the pending FitzPatrick acquisition as follows:

	Pre-tax Expense For the Year Ended December 31, 2016								
Merger Integration and Acquisition Expense:	**Exelon** [(a)]	**Generation** [(a)]	**ComEd**	**PECO**	**BGE**	**PHI** [(a)]	**Pepco** [(a)]	**DPL** [(a)]	**ACE** [(a)]
Transaction [(c)]	34	2							
Employee-related [(d)]	77	10	2	1	1	64	30	18	15
Other [(e)]	52	44	(8)	4	(2)	5	(2)	2	4
Total	$ 163	$ 56	$ (6)	$ 5	$ (1)	$ 69	$ 28	$ 20	$ 19

	Pre-tax Expense For the Year Ended December 31, 2015				
Merger Integration and Acquisition Expense:	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Financing [(b)]	$ 21	$	$	$	$
Transaction [(c)]	23				
Other [(e)]	51	32	9	4	5
Total	$ 95	$ 32	$ 9	$ 4	$ 5

(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 and costs associated with the exchange and redemption of mandatorily redeemable debt.

(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 year ended December 31, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $11 million, $4 million and $16 million incurred at ComEd, BGE, Pepco, DPL and PHI, respectively, that has been deferred and recorded as a regulatory asset for anticipated recovery. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for more information. For the year ended December 31, 2015, includes costs to integrate CENG, Constellation and Integrys systems into Exelon and terminate certain Constellation debt agreements. Also includes professional fees primarily related to integration for the PHI acquisition.

As of December 31, 2016, Exelon expects to incur total PHI acquisition and integration related costs of approximately $700 million, excluding merger commitments. Of this amount, including costs incurred from 2014 through December 31, 2016, Exelon and PHI have incurred approximately $610 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 $30 million for integration costs expected to be capitalized to Property, plant and equipment.

Significant 2016 Transactions and Developments

PHI Acquisition

On March 23, 2016, Exelon completed its acquisition of PHI for a total cash purchase price of $7.1 billion, significantly expanding its regulated utility business and resulting in a total of over 10 million utility customers. In accounting for the acquisition as a business combination, Exelon and PHI recorded $4.0 billion in goodwill. 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 customer rate credits, funding for energy efficiency and delivery system modernization programs, and other various requirements, for which Exelon recorded $513 million of Operating and maintenance expense for the year ended December 31, 2016. The Registrants have also incurred costs for evaluating, structuring and executing the transaction, as well as integrating the former PHI businesses into Exelon. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to the Consolidated Financial Statements for additional information regarding the PHI acquisition and related costs.

Illinois Future Energy Jobs Act

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA is effective June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd s electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd s customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs. FEJA establishes new or adjusts existing rate recovery mechanisms for ComEd to recover costs associated with the new or expanded energy efficiency and RPS requirements. Regulatory or legal challenges over the validity of FEJA are possible. See Note 3 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding FEJA. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for the impacts of ZES on Generation s Consolidated Balance Sheets and Consolidated Statements of Operations and Comprehensive Income.

New York Clean Energy Standard

On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of a Tier 3 ZEC program targeted at preserving the environmental attributes of qualifying zero-emissions nuclear-powered generating facilities, including CENG s Ginna, and Nine Mile Point and Entergy Nuclear Fitzpatrick LLC s (Entergy) 838 MW single unit James A. FitzPatrick facilities. On November 18, 2016, required contracts with the New York State Energy Research and Development Authority (NYSERDA) were executed for each of these three plants.

Regulatory and legal challenges over the validity the New York CES have been made, the outcomes of which remain uncertain. Also in August 2016, Generation executed a series of agreements with Entergy to acquire the Fitzpatrick nuclear generating station, subject to various regulatory approvals. The transaction is anticipated to close in the first or second quarter of 2017. See Note 3 Regulatory Matters Matters of the Combined Notes to the Consolidated Financial Statements for regulatory updates related to the New York CES, Note 9 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.

Potential Early Nuclear Plant Retirements

Exelon and Generation continually 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 and 2016, Generation identified the Clinton, Quad Cities, Ginna, Nine Mile Point, and Three Mile Island nuclear plants as having the greatest risk of early retirement based on economic valuation and other factors. On June 2, 2016, Generation announced its decision to shut down the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively; thereby resulting in accelerated depreciation for these plant assets thereafter. With the passage of the Illinois ZES on December 7, 2016, Generation reversed its original decision, and revised the expected economic useful lives for both facilities to 2027 for Clinton and to 2032 for Quad Cities. Furthermore, assuming the successful implementation of the Illinois ZES and the New York CES for their entire terms, Generation no longer considers Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk of early retirement. Generation currently considers Three Mile Island to be at the greatest risk of early retirement due to current economic valuations and other factors. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

Like-Kind Exchange

On September 19, 2016, the United States Tax Court rejected Exelon s position on its 1999 income tax return to defer under the like-kind exchange provisions of the IRC $1.2 billion of tax gain on the sale of ComEd s fossil generating assets. In addition, contrary to Exelon s evaluation that any penalty was unwarranted, the Tax Court ruled that Exelon is liable for the penalty and interest thereon asserted by the IRS, pursuant to which Exelon and ComEd recorded charges to earnings in 2016 of $106 million and $86 million, respectively. Exelon expects to timely appeal this decision to the U.S. Court of Appeals for the Seventh Circuit. While awaiting a final calculation from the IRS, Exelon estimates an approximate $1.4 billion payment will be due, including $300 million form ComEd, in the second quarter of 2017 at the time it expects to file its appeal. Of this amount, Exelon deposited with the IRS $1.25 billion in October 2016, with the remainder to be paid at the time the appeal is filed. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for further information related to the like-kind exchange tax matter, including Exelon s agreement to hold ComEd harmless from any unfavorable impacts of after-tax interest or penalty amounts on ComEd s equity.

BGE 2015 Electric and Natural Gas Distribution Base Rates

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, which included recovery of electric and

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natural gas smart grid initiative costs. 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, which BGE filed a petition for rehearing on and certain of which were reversed by the MDPSC in an order issued on July 29, 2016. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

Pepco Maryland 2016 Electric Distribution Base Rates

On November 15, 2016, the MDPSC approved an increase in electric distribution base rates of $53 million based on a ROE of 9.55%. The new rates became effective for services rendered on or after November 15, 2016. MDPSC also approved Pepco s recovery of substantially all of its capital investment and regulatory assets associated with its AMI program as part of the newly effective rates as well as recovery over a five-year period of transition costs related to a new billing system implemented in 2015. As a result, during the fourth quarter of 2016, Exelon, PHI and Pepco established a regulatory asset of $13 million, wrote off $3 million in disallowed AMI costs and recorded a pre-tax credit to net income for $10 million. Additionally, the MDPSC denied Pepco s request to extend its Grid Resiliency Program surcharge for new system reliability and safety improvement projects, with costs for such programs to be recovered going forward through base rates. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

DPL Delaware 2016 Electric and Natural Gas Distribution Base Rates

The DPSC approved provisional increases in annual electric and natural gas distribution base rates of $2.5 million effective May 17, 2016, and an additional $30 million effective December 17, 2016, for electric and of $2.5 million effective May 17, 2016, and an additional $10 million effective December 17, 2016, for gas. These increases are subject to refund based on the final DPSC orders. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

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 each of the rate increases two months after filing the applications which were effective July 16, 2016. On December 1, 2016, the DPSC approved that an additional $30 million in electric distribution base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order, and an additional $10 million in gas base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

ACE 2016 Electric Distribution Base Rates

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, most likely in the first quarter of 2017. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information.

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Exelon s Strategy and Outlook for 2017 and Beyond

Exelon s value proposition and competitive advantage come from its scope and its core strengths of operational excellence and financial discipline. Exelon leverages its integrated business model to create value. Exelon s regulated and competitive businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

- Exelon s utilities provide a foundation for stable earnings, which translates to a stable currency in our stock.

- Generation s competitive businesses provide free cash flow to invest primarily into the utilities and in long-term, contracted assets and to reduce debt.

Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change.

Exelon s utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The 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 at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of resources and best practices to achieve improved operational and financial results. Additionally, ComEd, PECO and BGE anticipate making significant future investments in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation s competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. Generation s electricity generation strategy is to pursue opportunities that provide stable revenues and generation to load matching to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. Generation s customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon s financial priorities are to maintain investment grade credit metrics at each of the Registrants, to maintain optimal capital structure and to return value to Exelon s shareholders with an attractive dividend throughout the energy commodity market cycle and through stable earnings growth. Exelon s Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

Various market, financial, regulatory, legislative and operational factors could affect the Registrants success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS for additional information.

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 was achieved by the end of 2016. Approximately 60% of run-rate savings are expected to be achieved by the end of 2017 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.

Growth Opportunities

Management continually evaluates growth opportunities aligned with Exelon s businesses, assets and markets, leveraging Exelon s expertise in those areas and offering sustainable returns.

Regulated Energy Businesses. The PHI merger provides an opportunity to accelerate Exelon s regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $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 2021. The Utility Registrants invest in rate base where beneficial to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made at the lowest reasonable cost to customers.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements 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 December 31, 2016, Generation has currently approved plans to invest a total of approximately $1 billion in 2017 through 2019 on capital growth projects (primarily new plant construction and distributed generation).

Liquidity Considerations

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.6 billion, $5.3 billion, $1.0 billion, $0.6 billion, $0.6 billion, $0.5 billion, $0.5 billion and $0.4 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.5 billion. See Liquidity and Capital Resources Credit Matters Exelon Credit Facilities below.

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Project Financing

Generation utilizes individual project financings as a means to finance the construction of various generating asset projects. Project financing is based upon a nonrecourse financial structure, in which project debt and equity used to finance the project are paid back from the cash generated by the newly constructed asset once operational. Borrowings under these agreements are secured by the assets and equity of each respective project. The lenders do not have recourse against Exelon or Generation in the event of a default. If a specific project financing entity does not maintain compliance with its specific nonrecourse debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, the lenders or security holders would generally have rights to foreclose against the project-specific assets and related collateral. The potential requirement to satisfy its associated debt or other borrowings earlier than otherwise anticipated could lead to impairments due to a higher likelihood of disposing of the respective project-specific assets significantly before the end of their useful life. See Note 14 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on nonrecourse debt.

ExGen Texas Power

In September 2014, ExGen Texas Power, LLC (EGTP), an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. EGTP s operating cash flows have been negatively impacted by certain market conditions including, but not limited to: low power prices, higher fuel prices and the seasonality of its cash flows . Despite the declining operating cash flows, EGTP remains in compliance with its covenants related to the project specific financing. Management continues to monitor the project entity s short term liquidity needs. See Note 14 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the EGTP.

Other Key Business Drivers and Management Strategies

Utility Rates and Rate Proceedings

The Utility Registrants file rate cases with their regulatory commissions seeking increases or decreases to their electric transmission and distribution, and gas distribution rates to recover their costs and earn a fair return on their investments. The outcomes of these regulatory proceedings impact the Utility Registrants current and future results of operations, cash flows and financial position. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further details on these regulatory proceedings.

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,

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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) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015). On May 10, 2016, FERC largely denied rehearing, and a number of parties appealed to the U.S. Court of Appeals for the DC Circuit for review of the decision. It is too early in the process to predict the appeal outcome.

MISO Capacity Market Results

On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the zone 4 region in downstate Illinois increased to $150 per MW per day beginning in June 2015, an increase from the prior pricing of $16.75 per MW per day that was in effect from June 2014 to May 2015. Generation had an offer that was selected in the auction. However, due to Generation s ratable hedging strategy, the results of the capacity auction have not had a material impact on Exelon s and Generation s consolidated results of operations and cash flows.

Additionally, in late May and June 2015, separate complaints were filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative, Public Citizens, Inc., and the Illinois Industrial Energy Consumers challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that 1) the results of the capacity auction for zone 4 are not just and reasonable, 2) the results should be suspended, set for hearing and replaced with a new just and reasonable rate, 3) a refund date should be established and that 4) certain alleged behavior by one of the market participants other than Exelon or Generation, be investigated.

On October 1, 2015, the FERC announced that it was conducting a non-public investigation (that does not involve Exelon or Generation) into whether market manipulation or other potential violations occurred related to the auction. On December 31, 2015, the FERC issued a decision that certain of the rules governing the establishment of capacity prices in downstate Illinois are not just and reasonable on a prospective basis. The FERC ordered that certain rules be changed prior to the April 2016 auction which set capacity prices for the 2016/2017 planning year. In response to this order, MISO filed certain rule changes with the FERC. On March 18, 2016, FERC largely denied rehearing of its December 31, 2015 order. 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. Generation cannot predict the impact the FERC order may ultimately have on future auction results, capacity pricing or decisions related to the potential early retirement of the Clinton nuclear plant, however, such impacts could be material to Generation s future results of operations and cash flows. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement.

MISO has acknowledged the need for capacity market design changes in the zone 4 regions, and on November 1, 2016 filed a comprehensive capacity market proposal for the zone 4 region (as well as another zone). It is too early to predict the outcome of that filing. Exelon is generally supportive of such changes. However, several fossil generators have requested that FERC impose an expanded minimum offer price rule (MOPR) that could affect capacity offers from the Clinton nuclear plant. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on the impacts of the MISO announcement. Exelon is actively participating in this aspect of the proceeding, seeking to avoid the implementation of such a MOPR mechanism. However, it is too early in the proceeding to predict.

Subsidized Generation

The rate of expansion of subsidized generation, in the markets in which Generation s output is sold can negatively impact wholesale power prices, and in turn, Generation s results of operations.

Various states have attempted to implement or propose legislation, regulations or other policies to subsidize new generation development which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term Capacity Pilot Program Act (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between the price eligible generators receive in the capacity market and the price guaranteed under the 15-year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV was required to construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland. The CfD mandated that utilities (including BGE, Pepco and DPL) pay (or receive) the difference between CPV s contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others challenged the constitutionality and other aspects of the New Jersey legislation in federal court. The 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. Each of those decisions was upheld by the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit, respectively. On April 19, 2016, the U.S. Supreme Court affirmed the decision of the U.S. Court of Appeals for the Fourth Circuit, and subsequently denied certiorari with respect to the appeal from the U.S. Court of Appeals for the Third Circuit, leaving in place that court s decision. The matter is now considered closed.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM s capacity market auctions. To the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon. While the court decisions are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon s 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 would 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 for what was collectively more than 6,000MW of primarily coal-fired generation. Thus, the Riders were similar to the CfDs described above (except that the PPA Riders in Ohio would apply to existing generation facilities whereas the CfDs applied to new generation facilities). While FERC orders on April 27, 2016 largely alleviated the concerns related to the Riders by holding that the PPAs ran afoul of affiliate restrictions on FE and AEP, we continue to closely monitor developments in Ohio.

In addition, Exelon continues to monitor developments in Maryland, New Jersey, and other states and participates in stakeholder and other processes to ensure that similar state subsidies are not 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.

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs

PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that required subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact of certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs. However, in Exelon s view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

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

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 (0.3)%, 0.6%, (1.4)%, (1.7)%, 0.8% and (0.7)%, respectively, in 2017 compared 2016.

Retail Competition

Generation s retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

Strategic Policy Alignment

As part of its strategic business planning process, Exelon routinely reviews its hedging policy, dividend policy, operating and capital costs, capital spending plans, strength of its balance sheet and credit metrics, and sufficiency of its liquidity position, by performing various stress tests with differing variables, such as commodity price movements, increases in margin-related transactions, changes in hedging practices, and the impacts of hypothetical credit downgrades.

Exelon s board of directors declared first quarter 2016 dividends of $0.31 per share each on Exelon s common stock. The second, third and fourth quarter 2016 dividends declared was $0.318 on Exelon s common stock, and the first quarter 2017 dividends declared was $0.328 per share. The dividends for the first, second, third and fourth quarter 2016 were paid on March 10, 2016, June 10, 2016, September 9, 2016 and December 9, 2016, respectively. The first quarter 2017 dividend is payable on March 10, 2017.

Exelon s Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

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 2017 and 2018. 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 December 31, 2016, the percentage of expected generation hedged for the major reportable segments was 91%-94%, 56%-59% and 28%-31% for 2017, 2018, and 2019 respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, 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 39% of Generation s uranium concentrate requirements from 2017 through 2021 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.

Tax Matters

Potential Corporate Tax Reform

The results of the November 2016 U.S. elections have introduced greater uncertainty with respect to federal tax policies. President Trump has stated that one of his top priorities is comprehensive tax reform and House Republicans plan to advance their tax reform blueprint . Tax reform proposals call for a reduction in the corporate federal income tax rate from the current 35% to as low as 15%. Other proposals provide, among other items, for the immediate deduction of capital investment expenditures and full or partial elimination of debt interest expense deductions. It is uncertain whether, to what extent or when these or any other changes in federal tax policies will be enacted or the transition time frame for such changes. Further, for the Utility Registrants, regulators may impose rate reductions to provide the benefit of any income tax expense reductions to customers and refund excess deferred income taxes previously collected through rates. The amounts and timing of any such rate changes would be subject to the discretion of the rate regulator in each specific jurisdiction. For these reasons, the Registrants cannot predict the impact any potential changes may have on their future results of operations, cash flows or financial position, and such changes could be material.

See Note 15 Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information

Environmental Legislative and Regulatory Developments

Exelon is actively involved in the EPA s development and implementation of environmental regulations for the electric industry, in pursuit of its business strategy to provide reliable, clean, affordable and innovative energy products. These efforts have most frequently involved air, water and waste controls for electric generating units, as set forth in the discussion below. These regulations have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Retirements of coal-fired power plants will continue as additional EPA regulations take effect, and as air quality standards are updated and further restrict emissions. Due to its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the EPA s rulemaking efforts, and it is uncertain whether any of these bills will become law.

Air Quality

In recent years, the EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act applicable to electric generating units. These regulations have resulted in more stringent emissions limits on fossil-fuel electric generating stations as states implement their compliance plans.

National Ambient Air Quality Standards (NAAQS). The EPA continues to review and update its NAAQS for conventional air pollutants relating to ground-level ozone and emissions of particulate matter, SO2 and NOx. Following five years of litigation, the EPA is implementing the Cross State Air Pollution Rule that requires 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, and otherwise contributes to non-attainment status of downwind states with the various NAAQS requirements.

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 of Convention). See ITEM 1. BUSINESS, Global Climate Change for further discussion.

Water Quality

Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation s power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. Those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, Ginna, Gould Street, Handley, Mountain Creek, Mystic 7, Nine Mile Point Unit 1, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. See ITEM 1. BUSINESS , Water Quality 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

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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 24 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 Legislative and Regulatory Developments

NRC Task Force on Fukishima

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 2017 through 2019 is expected to be between approximately $75 million and $100 million of capital and $15 million of operating expense. Generation s current assessments are specific to the Tier 1 recommendations. The NRC has not finalized actions with respect to the Tier 2 and Tier 3 recommendations and is expected to do so in 2017. 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.

Employees

During 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. In January 2017, an election was held at BGE which resulted in union representation for approximately 1,400 employees. BGE and IBEW Local 410 will begin negotiations for an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. No agreement has been finalized to date and management cannot predict the outcome of such negotiations.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the

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amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its Accounting and Disclosure Governance Committee on a regular basis and provides periodic updates on management decisions to the Audit Committee of the Exelon Board of Directors. Management believes that the accounting policies described below require significant judgment in their application, or incorporate estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation s ARO associated with decommissioning its nuclear units was $8.7 billion at December 31, 2016. The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple decommissioning outcome scenarios.

As a result of recent nuclear plant retirements in the industry, nuclear operators and third-party service providers are obtaining more information about costs associated with decommissioning activities. At the same time, regulators are gaining more information about decommissioning activities which could result in changes to existing decommissioning requirements. In addition, as more nuclear plants are retired, it is possible that technological advances will be identified that could create efficiencies and lead to a reduction in decommissioning costs. The availability of decommissioning trust funds could impact the timing of the decommissioning activities. Additionally, certain factors such as changes in regulatory requirements during plant operations or the profitability of a nuclear plant could impact the timing of plant retirements. These factors could result in material changes to Generation s current estimates as more information becomes available and could change the timing of plant retirements and the probability assigned to the decommissioning outcome scenarios.

The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing and/or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies

Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the expected costs (in current year dollars) and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within the industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation s nuclear units at least every five years, unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle.

Cost Escalation Factors

Generation uses cost escalation factors to escalate the decommissioning costs from the decommissioning cost studies discussed above through the assumed decommissioning period for each of the units. Cost escalation studies, updated on an annual basis, are used to determine escalation factors, and are based on inflation indices for labor, equipment and materials, energy, LLRW disposal and other costs. All of the nuclear AROs are adjusted each year for the updated cost escalation factors.

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Probabilistic Cash Flow Models

Generation s probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning cost levels, decommissioning approaches, and timing of plant shutdown on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are also assigned to four different decommissioning approaches. In response to expected increased security costs for spent fuel stored in the spent fuel pool (wet storage), in 2016 Generation has evaluated an alternative approach for managing spent fuel between the date of a plant s cessation of operations and the fuel s acceptance for disposal by the DOE. This new approach, the Shortened SAFSTOR approach, provides for increased usage of dry cask storage for the spent fuel, and is now considered as one of the decommissioning approaches in determining the ARO as follows:

1. DECON a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

2. Delayed DECON similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities. Spent fuel is retained in existing location (either wet or dry storage) until DOE acceptance for disposal.

3. Shortened SAFSTOR similar to the DECON scenario but with generally a 30 year delay prior to onset of decommissioning activities. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

4. SAFSTOR a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations. Spent fuel is transferred to dry cask storage as soon as possible until DOE acceptance for disposal.

The actual decommissioning approach selected once a nuclear facility is shutdown will be determined by Generation at the time of shutdown and may be influenced by multiple factors including the funding status of the nuclear decommissioning trust fund at the time of shutdown.

The assumed plant shutdown timing scenarios include the following four alternatives: (1) the probability of operating through the original 40-year nuclear license term, (2) the probability of operating through an extended 60-year nuclear license term (regardless of whether such 20-year license extension has been received for each unit), (3) the probability of a second, 20-year license renewal for some nuclear units, and (4) the probability of early plant retirement for certain sites due to changing market conditions and regulatory environments. The successful operation of nuclear plants in the U.S. beyond the initial 40-year license terms has prompted the NRC to consider regulatory and technical requirements for potential plant operations for an 80-year nuclear operating term. As power market and regulatory environment developments occur, Generation evaluates and incorporates, as necessary, the impacts of such developments into its nuclear ARO assumptions and estimates.

Generation s probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal. Generation currently assumes DOE will begin accepting SNF in 2030. The SNF acceptance date assumption is based on management s estimates of the amount of time required for DOE to select a site location and develop the necessary infrastructure for long-term SNF storage. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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License Renewals

Except for its Clinton unit, Generation has successfully obtained initial 20-year operating license renewal extensions (i.e. extending the total license term to 60 years) for all of its operating nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG). Generation intends to apply for an initial 20-year renewal for the Clinton unit. No prior Generation license extension application has been denied.

Discount Rates

The probability-weighted estimated future cash flows for the various assumed scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above. Increases in the ARO as a result of upward revisions in estimated undiscounted cash flows are considered new obligations and are measured using a current CARFR as the increase creates a new cost layer within the ARO. Any decrease in the estimated undiscounted future cash flows relating to the ARO are treated as a modification of an existing ARO cost layer and, therefore, is measured using the average historical CARFR rates used in creating the initial ARO cost layers.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation s future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $8.7 billion to approximately $9.7 billion.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2015 CARFRs rather than the 2016 CARFRs in performing its annual 2016 ARO update, Generation would have decreased the ARO by an additional $45 million; and ii) if the CARFR used in performing the annual 2016 ARO update was increased by 100 basis points or decreased by 50 basis points, the ARO would have decreased by $1.2 billion and increased by $150 million, respectively, as compared to the actual decrease of $385 million.

ARO Sensitivities

Changes in the assumptions underlying the ARO could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions may correspondingly change.

The following table illustrates the effects of changing certain ARO assumptions while holding all other assumptions constant (dollars in millions):

Change in ARO Assumption	Increase (Decrease) to ARO at December 31, 2016
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	$ 1,730
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 20 percent	1,610
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	470
Shorten each unit s probability weighted operating life assumption by 2 years	840
Extend the estimated date for DOE acceptance of SNF to 2035	140

For more information regarding accounting for nuclear decommissioning obligations, see Note 1 Significant Accounting Policies, Note 9 Early Nuclear Plant Retirements and Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon, Generation, ComEd, PHI and DPL)

As of December 31, 2016, Exelon s $6.7 billion carrying amount of goodwill primarily consists of $2.6 billion at ComEd relating to the acquisition of ComEd in 2000 as part of the formation of Exelon and $4 billion at PHI pursuant to Exelon s acquisition of PHI in the first quarter of 2016. DPL has $8 million of goodwill as of December 31, 2016, related to its 1995 acquisition of the Conowingo Power Company. Generation also has goodwill of $47 million as of December 31, 2016. Under the provisions of the authoritative guidance for goodwill, these entities are required to perform an assessment for possible impairment of their goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the reporting units below their carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or one level below an operating segment (known as a component) and is the level at which goodwill is tested for impairment. A component of an operating segment is a reporting unit if the component constitutes a business for which discrete financial information is available and its operating results are regularly reviewed by segment management. ComEd has a single operating segment, and PHI s operating segments are Pepco, DPL and ACE. See Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. There is no level below these operating segments for which operating results are regularly reviewed by segment management. Therefore, the ComEd, Pepco, DPL and ACE operating segments are also considered reporting units for goodwill impairment testing purposes. Exelon s and ComEd s $2.6 billion of goodwill has been assigned entirely to the ComEd reporting unit, while Exelon s and PHI s $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $1.7 billion, $1.1 billion and $1.2 billion, respectively. DPL s $8 million of goodwill is assigned entirely to the DPL reporting unit.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific conditions and events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment, or performs the qualitative assessment but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed.

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Exelon s, ComEd s and PHI s accounting policy is to perform a quantitative test of goodwill at least once every three years, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of the reporting unit below its carrying amount. The first step in the quantitative test compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd s, Pepco s, DPL s and ACE s businesses and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

Exelon, ComEd, PHI and DPL performed quantitative tests as of November 1, 2016, for their 2016 annual goodwill impairment assessments. The first step of the tests comparing the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second steps were required.

While the annual assessments indicated no impairments, certain assumptions used to estimate reporting unit fair values are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon s, ComEd s, PHI s or DPL s goodwill, which could be material. Based on the results of the annual goodwill tests performed as of November 1, 2016, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30%, 10%, 10% and 10%, respectively, for Exelon, ComEd and PHI to have failed the first step of their respective impairment tests. For the $8 million of goodwill recorded at DPL related to DPL s 1995 acquisition of the Conowingo Power Company, the fair value of the DPL reporting unit would have needed to decrease by more than 50% for DPL to fail the first step of the impairment test.

See Note 1 Significant Accounting Policies, Note 11 Intangible Assets and Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon, Generation and PHI)

In accordance with the authoritative accounting guidance, the assets acquired and liabilities assumed in an acquired business are recorded at their estimated fair values on the date of acquisition. The difference between the purchase price amount and the net fair value of assets acquired and liabilities assumed is recognized as goodwill on the balance sheet if it exceeds the estimated net fair value and as a bargain purchase gain on the income statement if it is below the estimated net fair value. Determining the fair value of assets acquired and liabilities assumed requires management s judgment, often utilizes independent valuation experts and involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. 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. See Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Unamortized Energy Contract Assets and Liabilities (Exelon, Generation, PHI, Pepco, DPL and ACE)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity and gas energy supply contracts Exelon has acquired as part of the PHI acquisition. The initial amount recorded represents the fair value of the contracts at the time of acquisition. At PHI, offsetting regulatory assets or liabilities were also recorded. The unamortized energy contract assets and liabilities and any corresponding regulatory assets or liabilities, respectively, are amortized over the life of the contract in relation to the expected realization of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues, respectively. Refer to Note 3 Regulatory Matters, Note 4 Mergers, Acquisitions, and Dispositions and Note 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements for further discussion.

Impairment of Long-lived Assets (All Registrants)

All Registrants regularly monitor and evaluate their long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Indicators of potential impairment may include a deteriorating business climate, including declines in energy prices, condition of the asset, specific regulatory disallowance, advances in technology, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

The review of long-lived assets and asset groups for impairment utilizes significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of the cash flows of other assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by the evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units as well as the associated intangible assets or liabilities recorded on the balance sheet. The cash flows from the generating units are generally evaluated at a regional portfolio level with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generating assets (typically contracted renewables).

On a quarterly basis, Generation assesses its asset groups for indicators of impairment. If indicators are present for a long-lived asset or asset group, a comparison of the undiscounted expected future cash flows to the carrying value is performed. When the undiscounted cash flow analysis indicates the carrying value of a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell. The fair value of the long-lived asset or asset group is dependent upon a market participant s view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances often do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. The determination of fair

value is driven by both internal assumptions that include significant unobservable inputs (Level 3) such as revenue and generation forecasts, projected capital, and maintenance expenditures and discount rates, as well as information from various public, financial and industry sources.

Generation evaluates its equity method investments and other investments in debt and equity securities to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature.

See Note 8 Impairment of Long-Lived Assets of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Exelon.

Depreciable Lives of Property, Plant and Equipment (All Registrants)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. These assets are generally depreciated on a straight-line basis, using the composite method in which depreciation is calculated using the average estimated useful life of assets within an asset group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are completed every five years, or more frequently if required by a rate regulator or if an event, regulatory action, or change in retirement patterns indicate an update is necessary.

For the Utility Registrants, depreciation studies generally serve as the basis for amounts allowed in customer rates for recovery of depreciation costs. Generally, the Utility Registrants adjust their depreciation rates for financial reporting purposes concurrent with adjustments to depreciation rates reflected in rates, unless the depreciation rates reflected in rates do not align with management s judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Consistent with each utility s regulatory recovery method, the Utility Registrant s depreciation expense for each asset group includes an amount for the estimated cost of dismantling and removing plant from service spread straight line over the asset group s average remaining useful life. Estimates for such removal costs are also evaluated in the periodic depreciation studies.

At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. See Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information on expected and potential early nuclear plant retirements.

Generation completed a depreciation rate study during the first quarter of 2015, which resulted in revised depreciation rates effective January 1, 2015.

ComEd is required to file an electric distribution depreciation rate study at least every five years with the ICC. ComEd completed an electric distribution and transmission depreciation study and filed the updated depreciation rates with both the ICC and FERC in January 2014, resulting in new depreciation rates effective first quarter 2014.

PECO is required to file electric distribution and gas depreciation rate studies at least every five years with the PAPUC. In March 2015, PECO filed a depreciation rate study with the PAPUC for both its electric distribution and gas assets, resulting in new depreciation rates for electric transmission assets effective January 1, 2015, for gas distribution assets effective July 1, 2015, and for electric distribution assets January 1, 2016.

The MDPSC does not mandate the frequency or timing of BGE s electric distribution or gas depreciation studies. In July 2014, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets, which became effective December 15, 2014.

The MDPSC does not mandate the frequency or timing of Pepco s electric distribution depreciation studies, while the DCPSC directs Pepco as to when it should file an electric distribution depreciation study. In 2016 and 2013, Pepco filed revised electric distribution depreciation rates with the MDPSC and DCPSC, respectively, with the new rates effective November 15, 2016 and April 16, 2014, respectively.

Neither the DPSC nor the MDPSC mandates the frequency or timing of DPL s electric distribution or gas depreciation studies. DPL filed revised depreciation rates for gas assets in 2006, with the new rates effective April 1, 2007. In 2013, DPL filed revised electric distribution depreciation rates with the MDPSC, with the new rates effective July 20, 2013. On July 20, 2016, DPL filed revised electric depreciation rates with the MDPSC as part of the electric distribution base rate filing. Any adjustments to the depreciation rates approved by the MDPSC are expected to take effect in the first quarter of 2017. On May 17, 2016, DPL filed revised electric and natural gas depreciation rates with the DPSC as part of the electric and natural gas base rate case filing. The DPSC is not required to issue a decision on the application within a specific period of time and adjustments to the depreciation rates will be made based on the outcome of the final orders, when received.

The NJBPU does not mandate the frequency or timing of ACE s electric distribution depreciation studies. In 2012, ACE filed revised electric distribution depreciation rates with the NJBPU, with the new rates effective July 1, 2013.

FERC does not mandate the frequency or timing of electric transmission depreciation studies.

Changes in estimated useful lives of electric generation assets and of electric and natural gas transmission and distribution assets could have a significant impact on the Registrants future results of operations. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding depreciation and estimated service lives of the property, plant and equipment of the Registrants.

Defined Benefit Pension and Other Postretirement Employee Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement employee benefit plans for substantially all employees. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is affected by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon s expected level of contributions to the plans, the incidence of participant mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. Exelon amortizes actuarial gains or losses in excess of a corridor of 10% of the greater of the projected benefit obligation or the market-related value (MRV) of plan assets over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

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Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets

The long-term EROA assumption used in calculating pension costs for Exelon plans was 7.00% for each of 2016, 2015 and 2014. For the predecessor periods of 2016, 2015 and 2014, the long-term EROA assumption used in calculating pension costs for the PHI plans was 6.50%, 6.50% and 7.00%, respectively. The weighted after-tax average EROA assumption used in calculating other postretirement benefit costs for Exelon plans was 6.71%, 6.50% and 6.59% in 2016, 2015 and 2014, respectively. For the predecessor periods of 2016, 2015 and 2014, the EROA assumption used in calculating other postretirement benefit costs for PHI plans was 6.75%, 6.75% and 7.25%, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. Over time, Exelon has decreased its equity investments and increased its investments in fixed income securities and alternative investments within the pension asset portfolio in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon s asset allocations. Exelon used an EROA of 7.00% and 6.60% to estimate its 2017 pension and other postretirement benefit costs, respectively.

Exelon calculates the amount of expected return on pension and other postretirement benefit plan assets by multiplying the EROA by the MRV of plan assets at the beginning of the year, taking into consideration anticipated contributions and benefit payments to be made during the year. In determining MRV, the authoritative guidance for pensions and postretirement benefits allows the use of either fair value or a calculated value that recognizes changes in fair value in a systematic and rational manner over not more than five years. For the majority of pension plan assets, Exelon uses a calculated value that adjusts for 20% of the difference between fair value and expected MRV of plan assets. Use of this calculated value approach enables less volatile expected asset returns to be recognized as a component of pension cost from year to year. For other postretirement benefit plan assets and certain pension plan assets, Exelon uses fair value to calculate the MRV.

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants pension and other postretirement benefit plans for the year ended December 31, 2016 were 7.30% and 6.02%, respectively, compared to an expected long-term return assumption of 7.00% and 6.71%, respectively.

Discount Rate

The discount rate used to determine the majority of the December 31, 2016 pension and other postretirement benefit obligations was 4.04%, representing a weighted-average of the rate for the majority of pension and other postretirement benefit plans. At December 31, 2016 and 2015, for both Exelon and PHI, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated future benefit distribution amounts under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

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The discount rate assumptions used to determine the obligation valuation at year end are also used to determine the cost for the following year. Exelon used discount rates ranging from 3.66% to 4.17% to estimate its 2017 pension and other postretirement benefit costs.

Health Care Cost Trend Rate

Assumed health care cost trend rates impact the costs reported for Exelon s other postretirement benefit plans for participant populations with plan designs that do not have a cap on cost growth. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty. Exelon assumed an initial health care cost trend rate of 5.50% for 2016, decreasing to an ultimate health care cost trend rate of 5.00% in 2017 for the majority of its plans.

Mortality

The mortality assumption is composed of a base table that represents the current expectation of life expectancy of the population adjusted by an improvement scale that attempts to anticipate future improvements in life expectancy. Exelon uses a mortality base table for its accounting valuation that is consistent with the IRS-required table for determining plan funding requirements pursuant to ERISA (referred to as RP-2000). Exelon is utilizing the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75% for its mortality improvement assumption. The mortality assumption is supported by an actuarial experience study on Exelon s plan participants performed in 2014.

Sensitivity to Changes in Key Assumptions

The following tables illustrate the effects of changing certain of the actuarial assumptions discussed above, while holding all other assumptions constant (dollars in millions):

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2016 cost:				
Discount rate [a]	0.5%	$ (65)	$ (16)	$ (81)
	(0.5)%	78	20	98
EROA	0.5%	(82)	(12)	(94)
	(0.5)%	82	12	94
Health care cost trend rate	1.00%	N/A	9	9
	(1.00)%	N/A	(8)	(8)
Change in benefit obligation at December 31, 2016:				
Discount rate [a]	0.5%	(1,119)	(250)	(1,369)
	(0.5)%	1,298	290	1,588
Health care cost trend rate	1.00%	N/A	105	105
	(1.00)%	N/A	(95)	(95)

(a) In general, the discount rate will have a larger impact on the pension and other postretirement benefit cost and obligation as the rate moves closer to 0%. Therefore, the discount rate sensitivities above cannot necessarily be extrapolated for larger increases or decreases in the discount rate. Additionally, Exelon implemented a liability-driven investment strategy for a portion of its pension asset portfolio in 2010. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

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Average Remaining Service Period

For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants average remaining service periods. The average remaining service period of Exelon s defined benefit pension plan participants was 11.9 years, 11.9 years and 11.8 years for the years ended December 31, 2016, 2015 and 2014, respectively. For the predecessor periods, the average remaining service period of PHI s defined benefit plans was approximately 11 years for both 2015 and 2014.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 9.0 years, 10.8 years and 9.1 years for the years ended December 31, 2016, 2015 and 2014, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.7 years, 9.7 years and 10.1 years for the years ended December 31, 2016, 2015 and 2014, respectively. For the predecessor periods, the average remaining service period of PHI s other postretirement benefit plans was approximately 11 years for both 2015 and 2014.

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

Exelon and the Utility Registrants account for their regulated electric and gas operations in accordance with the authoritative guidance, which requires Exelon and the Utility Registrants to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) 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 (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2016, Exelon and the Utility Registrants have concluded that the operations of each such Registrant meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of operations no longer meets the criteria of this guidance, Exelon and the Utility Registrants would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and Comprehensive Income and could be material. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon and the Utility Registrants.

For each regulatory jurisdiction in which they conduct business, Exelon and the Utility Registrants assess whether the regulatory assets and liabilities continue to meet the criteria for probable future recovery or settlement at each balance sheet date and when regulatory events occur. This assessment includes consideration of recent rate orders, historical regulatory treatment for similar costs in each Registrant s jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, each Registrant makes other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, for which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd s distribution formula rate, pursuant to EIMA, and FERC-approved

transmission formula rate tariffs for ComEd, BGE, Pepco, DPL and ACE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in each Registrant s jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon and the Utility Registrants for regulatory assets and regulatory liabilities are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

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 $2 million and $1 million for the years ended December 31, 2015 and December 31, 2014, respectively.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Accounting for Derivative Instruments (All Registrants)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. DPL also uses derivatives to reduce natural gas commodity volatility and to limit its customers exposure to natural gas price fluctuations under a hedging program approved by the DPSC. ACE has contracts to procure BGS electric supply that are executed through a competitive procurement process approved by the NJBPU. ComEd, PECO, BGE, Pepco, DPL and ACE do not enter into derivatives for proprietary trading purposes. The Registrants derivative activities are in accordance with Exelon s Risk Management Policy (RMP). See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants derivative instruments.

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The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Changes in management s assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium, contracts to purchase and sell capacity in certain ISO s, certain emission products and RECs do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement and neither the uranium, certain capacity, emission nor the REC markets are sufficiently liquid to conclude that physical forward contracts are readily convertible to cash. If these markets do become sufficiently liquid in the future and Generation would be required to account for these contracts as derivative instruments, the fair value of these contracts would be accounted for consistent with Generation s other derivative instruments. In this case, if market prices differ from the underlying prices of the contracts, Generation would be required to record mark-to-market gains or losses, which may have a significant impact to Exelon s and Generation s financial positions and results of operations.

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. Generally, hedge accounting is not elected for commodity transactions. Economic hedges for commodities are recorded at fair value through earnings. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for the Utility Registrants, changes in the fair value each period are recorded with a corresponding offsetting regulatory asset or liability if there is an ability to recover the associated costs.

Normal Purchases and Normal Sales Exception

As part of Generation s energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. The contracts that ComEd has entered into with suppliers as part of ComEd s energy procurement process, PECO s full requirement contracts under the PAPUC-approved DSP

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program, most of PECO s natural gas supply agreements, all of BGE s full requirement contracts and natural gas supply agreements that are derivatives and certain Pepco, DPL and ACE full requirement contracts qualify for and are accounted for under the normal purchases and normal sales exception.

Commodity Contracts

Identification of a commodity contract as an economic hedge requires Generation to determine that the contract is in accordance with the RMP. Generation reassesses its economic hedges on a regular basis to determine if they continue to be within the guidelines of the RMP.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. 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 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 Registrant s derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that take into account inputs such as contract terms, including maturity, and market parameters, and 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, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. 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. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments

The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, 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 economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates. 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. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 12 Fair Value of Financial Assets and Liabilities and Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants derivative instruments.

Taxation (All Registrants)

Significant management judgment is required in determining the Registrants provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the Registrants consolidated financial statements.

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 year ended December 31, 2015 is $34 million and $4 million for PHI and Pepco, respectively, and for the year ended December 31, 2014 is $1 million for both Pepco and ACE. The impact on all other PHI Registrants for years ended December 31, 2015 and December 31, 2014 is less than $1 million.

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and their intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. The Registrants also evaluate for negative evidence that could indicate the Registrant s inability to realize its deferred tax assets, such as historical operating loss or tax credit carryforward expiration. Based on the combined assessment, the Registrants record valuation allowances for deferred tax assets when they conclude it is more-likely-than-not such benefit will not be realized in future periods.

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Actual income taxes could vary from estimated amounts due to the future impacts of various items, including future changes in income tax laws, the Registrants forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2016 and 2015 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (All Registrants)

In the preparation of their financial statements, the Registrants make judgments regarding the future outcome of contingent events and record liabilities for loss contingencies that are probable and can be reasonably estimated based upon available information. The amounts recorded may differ from the actual expense incurred when the uncertainty is resolved. The estimates that the Registrants make in accounting for loss contingencies and the actual results that they record upon the ultimate resolution of these uncertainties could have a significant effect on their consolidated financial statements.

Environmental Costs

Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work and changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO, BGE, Pepco, DPL and ACE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants results of operations, financial position and cash flows. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information.

Other, Including Personal Injury Claims

The Registrants are self-insured for general liability, automotive liability, workers compensation, and personal injury claims to the extent that losses are within policy deductibles or exceed the amount of insurance maintained. The Registrants have reserves for both open claims asserted and an estimate of claims incurred but not reported (IBNR). The IBNR reserve is estimated based on actuarial assumptions and analysis and is updated annually. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding litigation and possible state and national legislative measures could cause the actual costs to be higher or lower than estimated. Accordingly, these claims, if resolved in a manner different from the estimate, could have a material effect on the Registrants results of operations, financial position and cash flows.

Revenue Recognition (All Registrants)

Sources of Revenue and Determination of Accounting Treatment

The Registrants earn revenues from various business activities including: the sale of energy and energy-related products, such as natural gas, capacity, and other commodities in non-regulated markets (wholesale and retail)*;* the sale and delivery of electricity and natural gas in regulated markets; and the provision of other energy-related non-regulated products and services.

The appropriate accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable accounting standards. The Registrants primarily use accrual and mark-to-market accounting as discussed in more detail below.

Accrual Accounting

Under accrual accounting, the Registrants record revenues in the period when services are rendered or energy is delivered to customers. The Registrants generally use accrual accounting to recognize revenues for sales of electricity, natural gas and other commodities as part of their physical delivery activities. The Registrants enter into these sales transactions using a variety of instruments, including non-derivative agreements, derivatives that qualify for and are designated as normal purchases and normal sales (NPNS) of commodities that will be physically delivered, sales to utility customers under regulated service tariffs and spot-market sales, including settlements with independent system operators.

Mark-to-Market Accounting

The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that meet the definition of a derivative for which they are not permitted, or have not elected, the NPNS exception. These mark-to-market transactions primarily relate to commodity price risk management activities. Mark-to-market revenues and expenses include: inception gains or losses on new transactions where the fair value is observable and realized; and unrealized gains and losses from changes in the fair value of open contracts.

Unbilled Revenues

The determination of Generation s and the Utility Registrants retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, revenues may fluctuate monthly as a result of customers electing to use an alternate supplier, since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

See Note 6 Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information.

Regulated Distribution & Transmission Revenues

ComEd s EIMA distribution formula rate provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism.

ComEd s, BGE s, Pepco s, DPL s and ACE s FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates,

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ComEd, BGE, Pepco, DPL and ACE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that each Registrant believes are probable of approval by FERC in accordance with the formula rate mechanism.

Distribution and transmission formula rates require significant estimates. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred, investments made, allowed ROE, and actions by regulators or courts.

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for more information on the potential impacts of the new revenue accounting standard effective for annual reporting periods beginning on or after December 15, 2017.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd, PECO and BGE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. At December 31, 2015, Pepco, DPL and ACE estimated the allowance for uncollectible accounts based on specific identification of material amounts at risk by customer and maintained a reserve based on their historical collection experience. At December 31, 2016, Pepco, DPL and ACE aligned the estimation of their allowance for uncollectible accounts to be consistent with ComEd, PECO and BGE, as described above. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. The Utility Registrant customers accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants customer accounts are written off consistent with approved regulatory requirements. Utility Registrants allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. See Note 6 Accounts Receivable of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2016, 2015 and 2014 set forth below include intercompany transactions, which are eliminated in Exelon s consolidated financial statements.

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Net Income (Loss) Attributable to Common Shareholders by Registrant

	For the Years Ended December 31, 2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	For the Year Ended December 31, 2014	Favorable (unfavorable) 2015 vs. 2014 variance
Exelon	$ 1,134	$ 2,269	$ (1,135)	$ 1,623	$ 646
Generation	496	1,372	(876)	835	537
ComEd	378	426	(48)	408	18
PECO	438	378	60	352	26
BGE	286	275	11	198	77
Pepco	42	187	(145)	171	16
DPL	(9)	76	(85)	104	(28)
ACE	(42)	40	(82)	46	(6)

	Successor	*Predecessor*			
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014	Favorable (unfavorable) 2015 vs. 2014 variance
PHI	$ (61)	$ 19	$ 327	$ 242	$ 85

Results of Operations Generation

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014 [(a)]	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 17,751	$ 19,135	$ (1,384)	$ 17,393	$ 1,742
Purchased power and fuel expense	8,830	10,021	1,191	9,925	(96)
Revenues net of purchased power and fuel expense [(b)]	8,921	9,114	(193)	7,468	1,646
Other operating expenses					
Operating and maintenance	5,641	5,308	(333)	5,566	258
Depreciation and amortization	1,879	1,054	(825)	967	(87)
Taxes other than income	506	489	(17)	465	(24)
Total other operating expenses	8,026	6,851	(1,175)	6,998	147
Equity in losses of unconsolidated affiliates				(20)	20

Gain (Loss) on sales of assets	(59)	12	(71)	437	(425)
Gain on consolidation and acquisition of businesses				289	(289)
Operating income	836	2,275	(1,439)	1,176	1,099
Other income and (deductions)					
Interest expense	(364)	(365)	1	(356)	(9)
Other, net	401	(60)	461	406	(466)
Total other income and (deductions)	37	(425)	462	50	(475)
Income before income taxes	873	1,850	(977)	1,226	624
Income taxes	290	502	212	207	(295)
Equity in losses of unconsolidated affiliates	(25)	(8)	(17)		(8)
Net income	558	1,340	(782)	1,019	321
Net income (loss) attributable to noncontrolling interests	62	(32)	94	184	(216)
Net income attributable to membership interest	$ 496	$ 1,372	$ (876)	$ 835	$ 537

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, the financial results include CENG s results of operations on a fully consolidated basis.
(b) Generation evaluates its operating performance using the measure of revenues net of purchased power and fuel expense. Generation believes that revenues net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenues net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Membership Interest

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Generation s net income attributable to membership interest decreased compared to the same period in 2015, primarily due to lower revenues net of purchased power and fuel expense, higher operating and maintenance expense, higher depreciation and amortization expense, and losses on sales of assets in 2016, partially offset by increased other income and decreased income tax expense. The decrease in revenues net of purchased power and fuel expense primarily relates to lower mark-to-market results in 2016 compared to 2015 and lower realized energy prices, partially offset by the Ginna Reliability Support Services Agreement 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 impairment of Upstream assets and certain wind projects, and increased costs related to the implementation of the cost management program. The increase in depreciation and amortization expense is primarily related to accelerated depreciation and amortization expense related to the previous 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 losses on sales of assets is primarily due to Generation s strategic decision to narrow the scope and scale of its growth and development activities. The increase in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Generation s net income attributable to membership interest increased compared to the same period in 2014 primarily due to higher revenue net of purchase power and fuel expense and lower operating and maintenance expense; partially offset by the absence of the 2014 gains recorded on the sales of Generation s ownership interest in generating stations, the absence of the 2014 gain recorded upon the consolidation of CENG, decreased other income and increased income tax expense. The increase in revenue, net of purchase power and fuel expense was primarily due to the inclusion of CENG s results on fully consolidated basis in 2015, the benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE SNF disposal fee, increased capacity prices, the inclusion of Integrys results in 2015, favorability from portfolio management optimization activities, increased load served, and mark-to-market gains in 2015 compared to mark-to-market losses in 2014, partially offset by lower margins resulting from the 2014 sale of generating assets, lower realized energy prices, and the absence of the 2014 fuel optimization opportunities in the South region due to extreme cold weather. The decrease in operating and maintenance expense was largely due to the reduction of long-lived asset impairment charges in 2015 versus 2014, partially offset by increased labor, contracting and materials expense due to the inclusion of CENG s results on a fully consolidated basis in 2015 and increased energy efficiency projects. The decrease in other income is primarily the result of the change in realized and unrealized gains and losses on NDT fund investments in 2015 as compared to 2014.

Revenues Net of Purchased Power and Fuel Expense

The basis for Generation s reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of

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ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation s hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation s six reportable segments are as follows:

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

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

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

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

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

Other Power Regions:

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

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

Canada represents operations across the entire country of Canada and includes the 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 the initial early retirement decision for Clinton and Quad Cities; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenues 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.

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For the years ended December 31, 2016 compared to 2015 and December 31, 2015 compared to 2014, Generation s revenues net of purchased power and fuel expense by region were as follows:

	2016	2015	2016 vs. 2015 Variance	2016 vs. 2015 % Change	2014	2015 vs. 2014 Variance	2015 vs. 2014 % Change
Mid-Atlantic [(a)(b)(e)]	$ 3,317	$ 3,571	$ (254)	(7.1)%	$ 3,431	$ 140	4.1%
Midwest [(c)]	2,971	2,892	79	2.7%	2,599	293	11.3%
New England	438	461	(23)	(5.0)%	351	110	31.3%
New York [(a)(e)]	742	634	108	17.0%	483	151	31.3%
ERCOT	281	293	(12)	(4.1)%	317	(24)	(7.6)%
Other Power Regions	336	250	86	34.4%	327	(77)	(23.5)%
Total electric revenues net of purchased power and fuel expense	8,085	8,101	(16)	(0.2)%	7,508	593	7.9%
Proprietary Trading	15	1	14	n.m.	42	(41)	(97.6)%
Mark-to-market gains (losses)	(41)	257	(298)	(116.0)%	(591)	848	n.m.
Other [(d)]	862	755	107	14.2%	509	246	48.3%
Total revenue net of purchased power and fuel expense	$ 8,921	$ 9,114	$ (193)	(2.1)%	$ 7,468	$ 1,646	22.0%

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning April 1, 2014, the financial results include CENG s results on a fully consolidated basis.

(b) 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 December 31, 2016.

(c) Results of transactions with ComEd are included in the Midwest region.

(d) Other represents activities not allocated to a region. See text above for a description of included activities. Includes a $57 million decrease to RNF, an $8 million increase to RNF, and a $124 million decrease to RNF for the amortization of intangible assets related to commodity contracts recorded at fair value for the years ended December 31, 2016, 2015, and 2014, respectively, and accelerated nuclear fuel amortization associated with the initial early retirement of Clinton and Quad Cities as discussed in Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements of $60 million for the year ended December 31, 2016.

(e) Includes $113 million and $169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2014. See Note 27 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

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Generation s supply sources by region are summarized below:

Supply Source (GWh)	2016	2015	2016 vs. 2015 Variance	2016 vs. 2015 % Change	2014	2015 vs. 2014 Variance	2015 vs. 2014 % Change
Nuclear Generation [a]							
Mid-Atlantic	63,447	63,283	164	0.3%	58,809	4,474	7.6%
Midwest	94,668	93,422	1,246	1.3%	94,000	(578)	(0.6)%
New York	18,684	18,769	(85)	(0.5)%	13,645	5,124	37.6%
Total Nuclear Generation	176,799	175,474	1,325	0.8%	166,454	9,020	5.4%
Fossil and Renewables							
Mid-Atlantic	2,731	2,774	(43)	(1.6)%	11,025	(8,251)	(74.8)%
Midwest	1,488	1,547	(59)	(3.8)%	1,372	175	12.8%
New England	6,968	2,983	3,985	133.6%	5,233	(2,250)	(43.0)%
New York	3	3		%	4	(1)	(25.0)%
ERCOT	6,785	5,763	1,022	17.7%	7,164	(1,401)	(19.6)%
Other Power Regions	8,179	7,848	331	4.2%	7,955	(107)	(1.3)%
Total Fossil and Renewables	26,154	20,918	5,236	25.0%	32,753	(11,835)	(36.1)%
Purchased Power							
Mid-Atlantic	16,874	8,160	8,714	106.8%	6,082	2,078	34.2%
Midwest	2,255	2,325	(70)	(3.0)%	2,004	321	16.0%
New England	16,632	24,309	(7,677)	(31.6)%	12,354	11,955	96.8%
New York				%	2,857	(2,857)	(100.0)%
ERCOT	10,637	10,070	567	5.6%	8,651	1,419	16.4%
Other Power Regions	13,589	18,773	(5,184)	(27.6)%	14,795	3,978	26.9%
Total Purchased Power	59,987	63,637	(3,650)	(5.7)%	46,743	16,894	36.1%
Total Supply/Sales by Region [b]							
Mid-Atlantic [c]	83,052	74,217	8,835	11.9%	75,916	(1,699)	(2.2)%
Midwest [c]	98,411	97,294	1,117	1.1%	97,376	(82)	(0.1)%
New England	23,600	27,292	(3,692)	(13.5)%	17,587	9,705	55.2%
New York	18,687	18,772	(85)	(0.5)%	16,506	2,266	13.7%
ERCOT	17,422	15,833	1,589	10.0%	15,815	18	0.1%
Other Power Regions	21,768	26,621	(4,853)	(18.2)%	22,750	3,871	17.0%
Total Supply/Sales by Region	262,940	260,029	2,911	1.1%	245,950	14,079	5.7%

(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 6,179 GWh, 7,310 GWh, and 10,571 GWh for the years ended December 31, 2016, 2015, and 2014, respectively.

(c)

Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region. As a result of the PHI Merger, includes affiliate sales to Pepco, DPL, and ACE in the Mid-Atlantic region for the successor period of March 24, 2016 to December 31, 2016.

Mid-Atlantic. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $254 million decrease in revenues net of purchased power and fuel expense in the Mid-Atlantic was primarily due to lower realized energy prices, decreased capacity prices and higher oil inventory write-downs in 2016, partially offset by increased load volumes served.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $140 million increase in revenues net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the inclusion of CENG s results on a fully consolidated basis for the full year in 2015, the benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), increased load volumes served, higher nuclear volumes, the cancellation of the DOE SNF disposal fee, and favorability from portfolio management optimization activities, partially offset by lower capacity revenues, and lower generation volumes due to the sale of generating assets.

Midwest. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $79 million increase in revenues net of purchased power and fuel expense in the Midwest was primarily due to decreased nuclear outage days and decreased nuclear fuel prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $293 million increase in revenues net of purchased power and fuel expense in the Midwest was primarily due to higher capacity revenues, increased load volumes served, the inclusion of Integrys results in 2015, the cancellation of the DOE SNF disposal fee in 2014, and favorability from portfolio management optimization activities, partially offset by lower nuclear volumes.

New England. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $23 million decrease in revenues net of purchased power and fuel expense in New England was primarily due to lower realized energy prices and higher oil inventory write-downs in 2016, partially offset by increased capacity prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $110 million increase in revenues net of purchased power and fuel expense in New England was primarily due to the benefit of lower cost to serve load, increased load volumes served, the inclusion of Integrys results in 2015, and favorability from portfolio management optimization activities, partially offset by lower generation volumes due to the sale of a generating asset.

New York. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $108 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the impact of the Ginna Reliability Support Service Agreement, partially offset by lower realized energy prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $151 million increase in revenues net of purchased power and fuel expense in New York was primarily due to the inclusion of CENG s results on a fully consolidated basis for the full year in 2015, increased nuclear volumes and the inclusion of Integrys results in 2015, partially offset by lower realized energy prices and decreased capacity revenues.

ERCOT. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $12 million decrease in revenues 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.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $24 million decrease in revenues net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices and a decrease in generation volumes due to the sale of a generating asset, partially offset by the absence of higher procurement costs for replacement power in 2014 and decreased fuel costs.

Other Power Regions. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $86 million increase in revenues net of purchased power and fuel expense in Other Power Regions was primarily due to higher realized energy prices.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $77 million decrease in revenues net of purchased power and fuel expense in Other Power Regions was primarily

due to the amortization of contracts recorded at fair value associated with prior acquisitions, lower realized energy prices, the absence of the 2014 fuel optimization opportunities, partially offset by increased generation from power purchase agreements, and decreased fuel costs.

Proprietary Trading. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $14 million increase in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to congestion activity.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $41 million decrease in revenues net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of gains on congestion trading products.

Mark-to-market. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. See Note 12 Fair Value of Financial Assets and Liabilities and Note 13 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Mark-to-market losses on economic hedging activities were $41 million in 2016 compared to gains of $257 million in 2015.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Mark-to-market gains on economic hedging activities were $257 million in 2015 compared to losses of $591 million in 2014.

Other. Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The $107 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 the initial early retirement decision for Clinton and Quad Cities as discussed in Note 9 Early Nuclear Plant Retirements of the Combined Notes to the Financial Statements.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The $246 million increase in other revenue net of purchased power and fuel was primarily due to the amortization of energy contracts recorded at fair value associated with prior acquisitions, the inclusion of Integrys gas results in 2015, and an increase in distributed generation and energy efficiency activity. See Note 11 Intangible Assets of the Combined Notes to Consolidated Financial Statements for information regarding energy contract intangibles.

Nuclear Fleet Capacity Factor

The following table presents nuclear fleet operating data for 2016, as compared to 2015 and 2014, 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 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.

	2016	2015	2014
Nuclear fleet capacity factor [(a)]	94.6%	93.7%	94.3%

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. As of April 1, 2014, CENG is included at ownership.

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Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The nuclear fleet capacity factor, which excludes Salem, increased in 2016 compared to 2015 primarily due to fewer refueling and non-refueling outage days. For 2016 and 2015, planned refueling outage days totaled 245 and 290, respectively, and non-refueling outage days totaled 63 and 82, respectively.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The nuclear fleet capacity factor, which excludes Salem, decreased in 2015 compared to 2014 primarily due to a higher number of refueling outage days and non-outage energy losses, partially offset by a lower number of unplanned outage days. For 2015 and 2014, planned refueling outage days totaled 290 and 275, respectively, and non-refueling outage days totaled 82 and 92, respectively.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2016 compared to 2015, consisted of the following:

	Increase (Decrease)
Impairment and related charges of certain generating assets [(a)]	$ 161
Merger and integration costs	27
Midwest Generation bankruptcy charges	10
ARO update [(b)]	(79)
Pension and non-pension postretirement benefits expense [(c)]	(42)
Corporate allocations [(d)]	(12)
Plant retirements and divestitures [(e)]	(50)
Accretion expense	(21)
Nuclear refueling outage costs, including the co-owned Salem plant [(f)]	(61)
Merger commitments	53
Labor, other benefits, contracting and materials [(g)]	185
Cost management program [(h)]	43
Curtailment of Generation growth and development activities [(i)]	24
Other	95
Increase in operating and maintenance expense	$ 333

(a) Reflects increased impairments in 2016 compared to 2015, primarily related to the impairments of certain Upstream assets and wind generating assets in 2016.
(b) Reflects a non-cash benefit pursuant to the annual update of the Generation nuclear decommissioning obligation related to the non-regulatory units.
(c) Reflects the favorable impact of higher pension and OPEB discount rates.
(d) Reflects a decreased share of corporate allocated costs.
(e) Reflects the impact of the Generation s previous decision to early retire the Clinton and Quad cities nuclear facilities.
(f) Reflects the favorable impacts of decreased nuclear outages in 2016.
(g)

Reflects an increase of labor, other benefits, contracting and materials costs primarily due to increased contracting costs related to energy efficiency projects and the inclusion of Pepco Energy Services results in 2016. Also includes cost of sales of our other business activities that are not allocated to a region.

(h) Represents the 2016 severance expense and reorganization costs related to a cost management program.

(i) Reflects the one-time recognition for asset impairment charges pursuant to Generation s strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities.

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The changes in operating and maintenance expense for 2015 compared to 2014, consisted of the following:

	Increase (Decrease) [a]
Impairment and related charges of certain generating assets [b]	$ (651)
Maryland merger commitments	(44)
Merger and integration costs	(28)
Midwest Generation bankruptcy charges	(14)
Decrease in asbestos bodily injury reserve	(12)
ARO update	8
Regulatory fees and assessments	10
Pension and non-pension postretirement benefits expense	15
Corporate allocations [c]	16
Accretion expense	18
Nuclear refueling outage costs, including the co-owned Salem plant [d]	64
Labor, other benefits, contracting and materials [e]	323
Other	37
Decrease in operating and maintenance expense	$ (258)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 operating results include CENG s results of operations on a fully consolidated basis from April 1, 2014 through December 31, 2014.
(b) Primarily relates to impairments of certain generating assets held-for-sale, Upstream assets, and wind generating assets during 2014 that did not reoccur in 2015.
(c) Reflects an increased share of corporate allocated costs primarily due to the inclusion of CENG beginning April 1, 2014.
(d) Reflects the unfavorable impacts of increased nuclear outages in 2015.
(e) Reflects an increase of labor, other benefits, contracting and materials costs primarily due to the inclusion of CENG on a fully consolidated basis in 2015. Also includes cost of sales of our other business activities that are not allocated to a region.

Depreciation and Amortization

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Depreciation and amortization expense increased primarily due to accelerated depreciation and increased nuclear decommissioning amortization related to the previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016, and increased depreciation expense due to ongoing capital expenditures.

Excluding the impacts of future capital additions, Generation expects total annual depreciation for Clinton and Quad Cities in 2017 and future years will be consistent with the annual depreciation recognized prior to the June 2016 early retirement decision, with the impact on prospective depreciation of the reduction in the plants book values as a result of the accelerated depreciation recorded from June 2, 2016 to December 6, 2016, being essentially offset by the impact of shortening Clinton s expected economic useful life from the original 2046 date to the now expected 2027 date.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in depreciation and amortization expense was primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015, increased nuclear decommissioning amortization, and an increase in ongoing capital expenditures.

Taxes Other Than Income

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The increase in taxes other than income was primarily due to an increase in gross receipts tax.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in taxes other than income was primarily due to the inclusion of CENG s results on a fully consolidated basis in 2015.

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Equity in Losses of Unconsolidated Affiliates

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The year-over-year change in Equity in losses of unconsolidated affiliates is primarily the result of increased losses on equity investments.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The year-over-year change in Equity in losses of unconsolidated affiliates is primarily the result of the consolidation of CENG s results of operations beginning April 1, 2014, which were previously accounted for under the equity method of accounting.

Gain (Loss) on Sales of Assets

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in gain (loss) on sales of assets is primarily related to the one-time recognition for a loss on sale of assets pursuant to Generation s strategic decision in the fourth quarter of 2016 to narrow the scope and scale of its growth and development activities, partially offset by a gain associated with Generation s sale of the retired New Boston generating site in 2016.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in gain (loss) on sales of assets is primarily related to the absence of $411 million of gains recorded on the sale of Generation s ownership interests in Safe Harbor Water Power Corporation, Fore River and West Valley generating stations in 2014. Refer to Note 4 Mergers, Acquisitions, and Dispositions in the Combined Notes to Consolidated Financial Statements for additional information.

Gain on Consolidation and Acquisition of Businesses

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in gain on consolidation and acquisition of businesses reflects the absence of a $261 million gain upon consolidation of CENG resulting from the difference in fair value of CENG s net assets as of April 1, 2014 and the equity method investment previously recorded on Generation s and Exelon s books and the settlement of pre-existing transactions between Generation and CENG recorded in 2014, and the absence of a $28 million bargain-purchase gain related to the Integrys acquisition recorded in 2014.

Interest Expense

The changes in interest expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Interest expense on long-term debt	$ 8	$ 53
Interest expense on interest rate swaps	1	22
Interest expense on tax settlements	16	(37)
Other interest expense	(26)	(29)
(Decrease) increase in interest expense, net	$ (1)	$ 9

Other, Net

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The increase in Other, net primarily reflects the net increase in realized and unrealized gains related to the NDT fund investments of Generation s Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $80 million and $(22) million for the years ended December 31, 2016 and 2015,

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respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in Other, net primarily reflects the net decrease in realized and unrealized gains related to the NDT fund investments of Generation s Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $(22) million and $67 million for the years ended December 31, 2015 and 2014, respectively, related to the contractual elimination of income tax expense associated with the NDT fund investments of the Regulatory Agreement Units. Refer to Note 16 Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT fund investments.

The following table provides unrealized and realized gains (losses) on the NDT fund investments of the Non-Regulatory Agreement Units recognized in Other, net for 2016, 2015 and 2014:

	2016	2015	2014
Net unrealized gains (losses) on decommissioning trust funds	$ 194	$ (197)	$ 134
Net realized gains on sale of decommissioning trust funds	35	66	77

Effective Income Tax Rate.

Generation s effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 33.2%, 27.1% and 16.9%, respectively. See Note 15 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 ComEd

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 5,254	$ 4,905	$ 349	$ 4,564	$ 341
Purchased power expense	1,458	1,319	(139)	1,177	(142)
Revenues net of purchased power expense [(a)(b)]	3,796	3,586	210	3,387	199
Other operating expenses					
Operating and maintenance	1,530	1,567	37	1,429	(138)
Depreciation and amortization	775	707	(68)	687	(20)
Taxes other than income	293	296	3	293	(3)
Total other operating expenses	2,598	2,570	(28)	2,409	(161)
Gain on sales of assets	7	1	6	2	(1)

Operating income	1,205	1,017	188	980	37
Other income and (deductions)					
Interest expense, net	(461)	(332)	(129)	(321)	(11)
Other, net	(65)	21	(86)	17	4
Total other income and (deductions)	(526)	(311)	(215)	(304)	(7)
Income before income taxes	679	706	(27)	676	30
Income taxes	301	280	(21)	268	(12)
Net income	$ 378	$ 426	$ (48)	$ 408	$ 18

(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

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. ComEd s Net income for the year ended December 31, 2016 was lower than the same period in 2015 primarily due to the recognition of the penalty and the after-tax interest 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.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. ComEd s Net income for the year ended December 31, 2015 was higher than the same period in 2014 primarily due to increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE), partially offset by unfavorable weather and volume.

Revenues Net of Purchased Power Expense

There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power expense, such as commodity 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 Combined Notes to Consolidated Financial Statements 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 revenues related to supplied energy, which is fully offset in Purchased power expense. Therefore, customer choice programs have no impact on Revenue net of purchased power expense.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2016, 2015 and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	**2015**	**2014**
Electric	72%	76%	80%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015 and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
	1,502,900	38%	1,655,400	42%	2,426,900	63%

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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 revenues 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 year ended December 31, 2016 compared to the same period in 2015, and for the year ended December 31, 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Weather	$ 54	$ (16)
Volume	(2)	(22)
Electric distribution revenue	69	180
Transmission revenue	97	48
Regulatory required programs	(31)	(1)
Uncollectible accounts recovery, net	(13)	27
Pricing and customer mix	14	(4)
Revenue subject to refund		9
Other	22	(22)
Increase in revenue net of purchased power	$ 210	$ 199

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 year ended December 31, 2016, favorable weather conditions increased Operating revenues net of purchased power expense when compared to the prior years. For the year ended December 31, 2015, unfavorable weather conditions reduced Operating revenues net of purchased power expense when compared to the prior years.

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 years ended December 31, 2016, 2015 and 2014 consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	5,715	6,091	6,341	(6.2)%	(9.9)%
Cooling Degree-Days	1,157	806	842	43.5%	37.4%

Heading and Cooling Degree-Days	For the Years Ended December 31, 2015	2014	Normal	% Change 2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	6,091	7,027	6,341	(13.3)%	(3.9)%
Cooling Degree-Days	806	799	842	0.9%	(4.3)%

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Volume. Revenue net of purchased power expense remained relatively consistent as a result of delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016, reflecting a consistent average usage per residential customer as compared to the same period in 2015. For the year ended December 31, 2015, Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer and the impacts of energy efficiency programs, as compared to the same period in 2014.

Electric Distribution Revenue. EIMA provides for a performance-based formula rate, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under 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. In addition, ComEd s allowed ROE is subject to reduction if ComEd does not deliver the reliability and customer service benefits to which it has committed over the ten-year life of the investment program. During the year ended December 31, 2016, electric distribution revenue increased $69 million, primarily due to increased capital investment and depreciation expense, partially offset by lower allowed ROE due to a decrease in treasury rates. During the year ended December 31, 2015, electric distribution revenue increased $180 million, primarily due to higher Operating and maintenance expense and increased capital investment, partially offset by lower allowed ROE due to decreased treasury rates. See Operating and Maintenance Expense below and Note 3 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 years ended December 31, 2016 and 2015, ComEd recorded increased transmission revenue due to increased capital investment, higher depreciation expense and increased highest daily peak load. See Operating and Maintenance Expense below and Note 3 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 ComEd s energy efficiency and demand response and purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. See Operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Uncollectible accounts recovery, net, represents recoveries under ComEd s uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Pricing and Customer Mix. For the year ended December 31, 2016, the increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix. For the year ended December 31, 2015, 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.

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Revenue Subject to Refund. ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. Revenue net of purchase power expense was higher for the year ended December 31, 2015, due to the one-time revenue refund recorded in 2014 associated with the 2007 Rate Case.

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

	Year Ended December 31, 2016	Year Ended December 31, 2015	Increase (Decrease) 2016 vs. 2015	Year Ended December 31, 2015	Year Ended December 31, 2014	Increase (Decrease) 2015 vs. 2014
Operating and maintenance expense baseline	$ 1,347	$ 1,353	$ (6)	$ 1,353	$ 1,214	$ 139
Operating and maintenance expense regulatory required programs [(a)]	183	214	(31)	214	215	(1)
Total operating and maintenance expense	$ 1,530	$ 1,567	$ (37)	$ 1,567	$ 1,429	$ 138

(a) Operating and maintenance expense for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

The changes in Operating and maintenance expense for year ended December 31, 2016, compared to the same period in 2015, and for the year ended December 31, 2015, compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials [(a)]	$ 12	$ 31
Pension and non-pension postretirement benefits expense [(b)]	(24)	19
Storm-related costs	(9)	27
Uncollectible accounts expense provision [(c)]	5	(7)
Uncollectible accounts expense recovery, net [(c)]	(18)	34
BSC costs [(d)]	29	30
Other	(1)	5
	(6)	139
Regulatory required programs		

Energy efficiency and demand response programs		(31)		(1)
Increase in operating and maintenance expense	$	(37)	$	138

(a) Primarily reflects increased contracting costs related to preventative maintenance and other projects for the year ended December 31, 2015.

(b) Primarily reflects the favorable impact of higher assumed pension and OPEB discount rates for the year ended December 31, 2016 and the unfavorable impact of lower assumed pension and OPEB discount rates for the year ended December 31, 2015.

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(c) 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. ComEd recorded a net decrease and increase in 2016 and 2015, respectively, in Operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in Operating revenues for the periods presented.
(d) Primarily reflects increased information technology support services from BSC during 2016 and 2015.

Depreciation and Amortization Expense

The increases in Depreciation and amortization expense for 2016 compared to 2015, and 2015 compared to 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense [(a)]	$ 58	$ 43
Regulatory asset amortization [(b)]	(5)	(28)
Other	15	5
Total increase	$ 68	$ 20

(a) Primarily reflects ongoing capital expenditures for the years ended December 31, 2016 and 2015.
(b) Primarily reflects a decrease in MGP regulatory asset amortization for the year ended December 31, 2015,

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income taxes remained relatively consistent for the year ended December 31, 2016 compared to the same period in 2015, and for the year ended December 31, 2015 compared to the same period in 2014.

Gain on Sale of Assets

Gain on sale of assets increased primarily due to the sale of land during the year ended December 31, 2016, compared to the same period in 2015. Gain on sale of assets remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Interest Expense, Net

The increases in Interest expense, net, for the year ended 2016 compared to the same period in 2015, and for the year ended 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease)	Increase (Decrease)

	2016 vs. 2015	2015 vs. 2014
Interest expense related to uncertain tax positions [(a)]	$ 109	$ 2
Interest expense on debt (including financing trusts) [(b)]	24	13
Other	(4)	(4)
Increase (decrease) in interest expense, net	$ 129	$ 11

(a) Primarily reflects the recognition of after-tax interest related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds for the years ended December 31, 2016 and 2015. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s debt obligations.

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Other, Net

The increase (decrease) in other, net, for the year ended 2016 compared to the same period in 2015, and for the year ended 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Other income and deductions, net [(a)]	$ (94)	$ 2
AFUDC equity	9	2
Other	(1)	
Increase (decrease) in other, net	$ (86)	$ 4

(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 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

Effective Income Tax Rate

ComEd s effective income tax rates for the years ended December 31, 2016, 2015 and 2014, were 44.3%, 39.7% and 39.6%, respectively. The increase in the effective income tax rate for the year ended December 31, 2016 compared to the same period in 2015 is primarily due to the recognition of a non-deductible penalty related to the Tax Court s decision on Exelon s like-kind exchange tax position in the third quarter of 2016. See Note 15 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)	**2016**	**2015**	**% Change 2016 vs. 2015**	**Weather-Normal % Change**	**2014**	**% Change 2015 vs. 2014**	**Weather-Normal % Change**
Retail Deliveries [(a)]							
Residential	27,790	26,496	4.9%	(0.6)%	27,230	(2.7)%	(1.5)%
Small commercial & industrial	31,975	31,717	0.8%	(0.3)%	32,146	(1.3)%	(0.9)%
Large commercial & industrial	27,842	27,210	2.3%	1.5%	27,847	(2.3)%	(2.0)%
Public authorities & electric railroads	1,298	1,309	(0.8)%	(0.8)%	1,358	(3.6)%	(2.6)%
Total retail deliveries	88,905	86,732	2.5%	0.2%	88,581	(2.1)%	(1.4)%

	As of December 31,		
Number of Electric Customers	**2016**	**2015**	**2014**
Residential	3,595,376	3,550,239	3,502,386
Small commercial & industrial	374,644	370,932	369,053
Large commercial & industrial	2,007	1,976	1,998
Public authorities & electric railroads	4,750	4,820	4,815
Total	3,976,777	3,927,967	3,878,252

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Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [(a)]					
Residential	$ 2,597	$ 2,360	10.0%	$ 2,074	13.8%
Small commercial & industrial	1,316	1,337	(1.6)%	1,335	0.1%
Large commercial & industrial	462	443	4.3%	434	2.1%
Public authorities & electric railroads	45	42	7.1%	46	(8.7)%
Total retail	4,420	4,182	5.7%	3,889	7.5%
Other revenue [(b)]	834	723	15.4%	675	7.1%
Total electric revenue [(c)]	$ 5,254	$ 4,905	7.1%	$ 4,564	7.5%

(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 $15 million, $4 million, and $4 million for the years ended December 31, 2016, 2015, and 2014, respectively.

Results of Operations PECO

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 2,994	$ 3,032	$ (38)	$ 3,094	$ (62)
Purchased power and fuel	1,047	1,190	143	1,261	71
Revenues net of purchased power and fuel expense [(a)]	1,947	1,842	105	1,833	9
Other operating expenses					
Operating and maintenance	811	794	(17)	866	72
Depreciation and amortization	270	260	(10)	236	(24)
Taxes other than income	164	160	(4)	159	(1)
Total other operating expenses	1,245	1,214	(31)	1,261	47

Gain on sales of assets		2	(2)		2
Operating income	702	630	72	572	58
Other income and (deductions)					
Interest expense, net	(123)	(114)	(9)	(113)	(1)
Other, net	8	5	3	7	(2)
Total other income and (deductions)	(115)	(109)	(6)	(106)	(3)
Income before income taxes	587	521	66	466	55
Income taxes	149	143	(6)	114	(29)
Net income attributable to common shareholder	$ 438	$ 378	$ 60	$ 352	$ 26

(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

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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 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

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. PECO s net income attributable to common shareholder for the year ended December 31, 2016 was higher than the same period in 2015, primarily due to an increase in Revenues 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.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. PECO s net income attributable to common shareholder for the year ended December 31, 2015 was higher than the same period in 2014, primarily due to a decrease in Operating and maintenance expense due to a decrease in storm costs.

Revenues Net of Purchased Power and Fuel Expense

Electric and natural gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO s electric supply and natural gas cost rates charged to customers are subject to adjustments as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with PECO s GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and natural gas revenues 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 customer s choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer Choice Program activity has no impact on electric and natural gas revenue net of purchase 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 years ended December 31, 2016, 2015, and 2014 consisted of the following:

	For the Years Ended December 31,		
	2016	**2015**	**2014**
Electric	70%	70%	70%
Natural Gas	26%	25%	22%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of	**% of total**	**Number of**	**% of total**	**Number of**	**% of total**

	customers	retail customers	customers	retail customers	customers	retail customers
Electric	587,200	36%	563,400	35%	546,900	34%
Natural Gas	81,300	16%	81,100	16%	78,400	16%

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The changes in PECO s Operating revenues net of purchased power and fuel expense for the years ended December 31, 2016 and December 31, 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	2016 vs. 2015 Increase (Decrease)			2015 vs. 2014 Increase (Decrease)		
	Electric	**Gas**	**Total**	**Electric**	**Gas**	**Total**
Weather	$ 1	$ (12)	$ (11)	$ 28	$ (19)	$ 9
Volume	6	4	10	4	7	11
Pricing	160	(1)	159	4	2	6
Regulatory required programs	(46)		(46)	(6)		(6)
Other	(7)		(7)	(12)	1	(11)
Total increase (decrease)	$ 114	$ (9)	$ 105	$ 18	$ (9)	$ 9

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. Operating revenues net of purchased power and fuel expense for the year ended December 31, 2016 was reduced by the impact of unfavorable weather conditions in PECO s service territory.

Operating revenues net of purchased power and fuel expense for the year ended December 31, 2015, was higher primarily due to the impact of favorable 2015 summer and first quarter winter weather conditions, partially offset by the impact of unfavorable fourth quarter 2015 winter 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 years ended December 31, 2016 and December 31, 2015 compared to the same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	4,041	4,245	4,613	(4.8)%	(12.4)%
Cooling Degree-Days	1,726	1,720	1,301	0.3%	32.7%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**2015 vs. Normal**
Heating Degree-Days	4,245	4,749	4,613	(10.6)%	(8.0)%
Cooling Degree-Days	1,720	1,311	1,301	31.2%	32.2%

Volume. The increase in Operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 and 2015, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages for gas and residential and small commercial and industrial electric classes. Additionally, the increase represents a shift in the volume profile across classes from large commercial and industrial classes to residential and small commercial and industrial classes for electric.

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Pricing. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 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 for further information.

The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2015 is primarily attributable to increased monthly customer demand in the commercial and industrial classes. The increase in natural gas operating revenues net of fuel expense as a result of pricing for the year ended December 31, 2015, is primarily attributable to higher overall effective rates due to decreased retail gas usage.

Regulatory Required Programs. This represents the change in operating revenues collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

Other. Other revenue, which can vary period to period, primarily includes wholesale transmission revenue, rental revenue, revenue related to late payment charges and assistance provided to other utilities through mutual assistance programs.

Operating and Maintenance Expense

	Year Ended December 31, 2016	Year Ended December 31, 2015	Increase (Decrease) 2016 vs. 2015	Year Ended December 31, 2015	Year Ended December 31, 2014	Increase (Decrease) 2015 vs. 2014
Operating and maintenance expense baseline	$ 740	$ 685	$ 55	$ 685	$ 761	$ (76)
Operating and maintenance expense regulatory required programs (a)	71	109	$ (38)	109	105	$ 4
Total operating and maintenance expense	$ 811	$ 794	$ 17	$ 794	$ 866	$ (72)

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

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The changes in Operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 22	$ 1
Storm-related costs	(9)	(78)[b]
Pension and non-pension postretirement benefits expense	(4)	3
PHI merger integration costs	6	2
BSC costs [a]	36	9
Uncollectible accounts expense	1	(22)
Other	3	9
	55	(76)
Regulatory required programs		
Smart meter	(28)	(3)
Energy efficiency	(7)	8
GSA	(2)	
Other	(1)	(1)
	(38)	4
Increase (decrease) in operating and maintenance expense	$ 17	$ (72)

(a) Primarily reflects increased information technology support services from BSC during 2016.
(b) Reflects a reduction of $67 million in incremental storm costs, primarily as a result of the February 5, 2014 ice storm.

Depreciation and Amortization Expense

The changes in Depreciation and amortization expense for 2016 compared to 2015 and 2015 compared to 2014, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense	$ 5	$ 13
Regulatory asset amortization	5	11
Increase in depreciation and amortization expense	$ 10	$ 24

Taxes Other Than Income

Taxes other than income, which can vary year to year, include municipal and state utility taxes, real estate taxes, and payroll taxes. Taxes other than income increased for the year ended December 31, 2016, compared to the same period in 2015 primarily due to an increase in gross receipts tax driven by increases in electric revenue, which was impacted primarily by the new distribution rates that went into effect in January 2016 .

Taxes other than income remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Interest Expense, Net

The increase in Interest expense, net for the year ended December 31, 2016, compared to the same period in 2015, primarily reflects an increase in interest expense due to the issuance of First and Refunding Mortgage Bonds in October 2015.

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Interest expense, net remained relatively consistent for the year ended December 31, 2015, compared to the same period in 2014.

Other, Net

Other, net remained relatively consistent for the year ended December 31, 2016, compared to the same period in 2015, and the year ended December 31, 2015, compared to the same period in 2014.

Effective Income Tax Rate

PECO s effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 25.4%, 27.4% and 24.5%, respectively. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	13,664	13,630	0.2%	0.4%	13,222	3.1%	0.3%
Small commercial & industrial	8,099	8,118	(0.2)%	0.5%	8,025	1.2%	0.6%
Large commercial & industrial	15,263	15,365	(0.7)%	(1.4)%	15,310	0.4%	(0.5)%
Public authorities & electric railroads	890	881	1.0%	1.0%	937	(6.0)%	(6.0)%
Total electric retail deliveries	37,916	37,994	(0.2)%	(0.3)%	37,494	1.3%	(0.1)%

Number of Electric Customers	As of December 31, 2016	2015	2014
Residential	1,456,585	1,444,338	1,434,011
Small commercial & industrial	150,142	149,200	149,149
Large commercial & industrial	3,096	3,091	3,103
Public authorities & electric railroads	9,823	9,805	9,734
Total	1,619,646	1,606,434	1,595,997

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [(a)]					

Residential	$ 1,631	$ 1,599	2.0%	$ 1,555	2.8%
Small commercial & industrial	430	428	0.5%	423	1.2%
Large commercial & industrial	234	221	5.9%	217	1.8%
Public authorities & electric railroads	32	31	3.2%	32	(3.1)%
Total retail	2,327	2,279	2.1%	2,227	2.3%
Other revenue [b]	204	207	(1.4)%	221	(6.3)%
Total electric operating revenues [c]	$ 2,531	$ 2,486	1.8%	$ 2,448	1.6%

(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.

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(b) Other revenue includes transmission revenue from PJM and wholesale electric revenue.
(c) Total electric revenue includes operating revenues from affiliates totaling $7 million, $1 million and $1 million for the years ended December 31, 2016, 2015, and 2014, respectively.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Retail sales	56,447	59,003	(4.3)%	1.5%	62,734	(5.9)%	3.3%
Transportation and other	27,630	27,879	(0.9)%	(0.1)%	27,208	2.5%	1.2%
Total natural gas deliveries	84,077	86,882	(3.2)%	1.0%	89,942	(3.4)%	2.6%

Number of Gas Customers	As of December 31, 2016	2015	2014
Residential	472,606	467,263	462,663
Commercial & industrial	43,668	43,160	42,686
Total retail	516,274	510,423	505,349
Transportation	790	827	855
Total	517,064	511,250	506,204

Gas revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Retail sales	$ 430	$ 511	(15.9)%	$ 608	(16.0)%
Transportation and other	33	35	(5.7)%	38	(7.9)%
Total natural gas operating revenues [b]	$ 463	$ 546	(15.2)%	$ 646	(15.5)%

(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) Total natural gas revenues includes operating revenues from affiliates totaling $1 million for the years ended December 31, 2016, 2015 and 2014.

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Results of Operations BGE

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 3,233	$ 3,135	$ 98	$ 3,165	$ (30)
Purchased power and fuel expense	1,294	1,305	11	1,417	112
Revenues net of purchased power and fuel expense [(a)]	1,939	1,830	109	1,748	82
Other operating expenses					
Operating and maintenance	737	683	(54)	717	34
Depreciation and amortization	423	366	(57)	371	5
Taxes other than income	229	224	(5)	221	(3)
Total other operating expenses	1,389	1,273	(116)	1,309	36
Gain on sales of assets		1	(1)		1
Operating income	550	558	(8)	439	119
Other income and (deductions)					
Interest expense, net	(103)	(99)	(4)	(106)	7
Other, net	21	18	3	18	
Total other income and (deductions)	(82)	(81)	(1)	(88)	7
Income before income taxes	468	477	(9)	351	126
Income taxes	174	189	15	140	(49)
Net income	294	288	6	211	77
Preference stock dividends	8	13	5	13	
Net income attributable to common shareholder	$ 286	$ 275	$ 11	$ 198	$ 77

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenues net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Net income attributable to common shareholder was higher primarily due to lower income tax expense and decreased preference stock dividends partially offset by slightly lower operating income. The lower income tax expense was driven by a one-time adjustment associated with transmission-related regulatory assets. The slight decrease in operating income was driven by an increase in Operating and maintenance expense as a result of cost disallowances which reduced certain regulatory assets and other long-lived assets stemming from the distribution rate orders issued by the MDPSC in June 2016 and July 2016 and increased storm costs. This increase in Operating and maintenance expense was offset by an increase in Revenues net of purchased power and fuel expense, 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.

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Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. Net income attributable to common shareholder was higher primarily due to an increase in Revenues net of purchased power and fuel expense as a result of the December 2014 electric and natural gas distribution rate order issued by the MDPSC, an increase in transmission formula rate revenues and a reduction in Operating and maintenance expense as a result of a decrease in bad debt expense and storm costs in the BGE service territory.

Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to Operating revenues that are offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Operating revenues and Purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE s electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC s market-based SOS and gas commodity programs, respectively.

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. This 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) at December 31, 2016, 2015 and 2014 consisted of the following:

	For the Years Ended December 31,		
	2016	**2015**	**2014**
Electric	59%	61%	60%
Natural Gas	57%	56%	53%

The number of retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2016, 2015 and 2014 consisted of the following:

	December 31, 2016		**December 31, 2015**		**December 31, 2014**	
	Number of Customers	**% of total retail customers**	**Number of Customers**	**% of total retail customers**	**Number of Customers**	**% of total retail customers**
Electric	337,000	27%	343,000	27%	364,000	29%
Natural Gas	151,000	23%	154,000	23%	161,000	25%

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The changes in BGE s Operating revenues net of purchased power and fuel expense for the year ended December 31, 2016 compared to the same period in 2015 and for the year ended December 31, 2015 compared to the same period in 2014, respectively, consisted of the following:

	2016 Increase (Decrease)			2015 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 24	$ 22	$ 46	$ 20	$ 35	$ 55
Regulatory required programs	15	2	17	4	2	6
Transmission revenue	30		30	11		11
Other, net	19	(3)	16	10		10
Total increase	$ 88	$ 21	$ 109	$ 45	$ 37	$ 82

Distribution Rate Increase. The increase in distribution revenues for the year ended December 31, 2016 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in June 2016 in accordance with the MDPSC approved electric and natural gas distribution rate case orders in June 2016 and July 2016. The increase in distribution revenue for the year ended December 31, 2015 was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in December 2014 in accordance with the MDPSC approved electric and natural gas distribution rate case order. See Note 3 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 year ended December 31, 2016 compared to the same period in 2015 and for the year ended December 31, 2015 compared to the same period in 2014, respectively, and normal weather consisted of the following:

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	4,427	4,666	4,684	(5.1)%	(5.5)%

Cooling Degree-Days	998	924	876	8.0%	13.9%

	For the Year Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**2015 vs. Normal**
Heating Degree-Days	4,666	5,091	4,663	(8.3)%	0.1%
Cooling Degree-Days	924	732	875	26.2%	5.6%

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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.

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 years ended December 31, 2016 and 2015, the increase in transmission revenue was primarily due to increases in rates to reflect capital investment and operating and maintenance expense recoveries. See Operating and Maintenance Expense below and Note 3 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 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Impairment on long-lived assets and losses on regulatory assets [(a)]	$ 52	$
Labor, other benefits, contracting and materials	7	12
Storm-related costs	18	(21)
Uncollectible accounts expense [(b)]	(14)	(49)
BSC costs [(c)]	11	13
Conduit lease settlement	(15)	
Other	(5)	11
Increase (Decrease) in operating and maintenance expense	$ 54	$ (34)

(a) See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Uncollectible accounts expense decreased primarily due to improved customer behavior and milder weather for the years ended December 31, 2016 and 2015.
(c) Primarily reflects increased information technology support services and other services from BSC for the year ended December 31, 2016 and increased information technology support services for the year ended 2015.

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in annual rental fees for access to the Baltimore City underground conduit system effective November 1, 2015, from $12 million to $42 million, subject to an annual increase thereafter based on the Consumer Price Index. BGE subsequently entered into litigation with the City regarding the amount of and basis for establishing the conduit fee. On November 30, 2016, the Baltimore City Board of Estimates approved a settlement agreement entered into between BGE and the City to resolve the disputes and pending litigation related to BGE s use of and payment for the underground conduit system. As a result of the settlement, the parties have entered into a six-year lease that reduces the annual expense to $25 million in the first three years and caps the annual expense in the last three years to not more than $29 million. BGE recorded a credit to Operating and maintenance expense in the fourth quarter of

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approximately $28 million for the reversal of the previously higher fees accrued in the current year as well as the settlement of prior year disputed fee true-up amounts. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the financial impacts of the newly agreed upon six-year lease.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense [(a)]	$ 10	$ 2
Regulatory asset amortization [(b)]	47	(6)
Other		(1)
Increase (Decrease) in depreciation and amortization expense	$ 57	$ (5)

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2016 compared to the same period 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 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Taxes Other Than Income

The change in taxes other than income for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Property tax	$ 6	$ 3
Franchise tax		1
Other		(1)
Increase in taxes other than income	$ 6	$ 3

Interest Expense, Net

The decrease in Interest expense, net for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Interest expense on debt (including financing trusts)	$ 5	$ (4)
Interest expense related to capitalization of interest / AFUDC	3	(2)
Interest expense related to uncertain tax positions		(1)
Interest Expense related to repayment of the rate stabilization bonds	(4)	
Increase (Decrease) in interest expense, net	$ 4	$ (7)

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Effective Income Tax Rate

BGE s effective income tax rates for the years ended December 31, 2016, 2015 and 2014 were 37.2%, 39.6% and 39.9%, respectively. See Note 15 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)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [a]							
Residential	12,740	12,598	1.1%	n.m.	12,974	(2.9)%	n.m.
Small commercial & industrial	3,040	3,119	(2.5)%	n.m.	3,086	1.1%	n.m.
Large commercial & industrial	13,957	14,293	(2.4)%	n.m.	14,191	0.7%	n.m.
Public authorities & electric railroads	283	294	(3.7)%	n.m.	311	(5.5)%	n.m.
Total electric deliveries	30,020	30,304	(0.9)%	n.m.	30,562	(0.8)%	n.m.

Number of Electric Customers	As of December 31, 2016	2015	2014
Residential	1,150,096	1,137,934	1,125,369
Small commercial & industrial	113,230	113,138	112,972
Large commercial & industrial	12,053	11,906	11,730
Public authorities & electric railroads	280	285	290
Total	1,275,659	1,263,263	1,250,361

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$ 1,554	$ 1,449	7.2%	$ 1,404	3.2%
Small commercial & industrial	277	273	1.5%	271	0.7%
Large commercial & industrial	449	469	(4.3)%	491	(4.5)%
Public authorities & electric railroads	35	32	9.4%	32	%
Total retail	2,315	2,223	4.1%	2,198	1.1%
Other revenue [b]	294	267	10.1%	262	1.9%
Total electric operating revenues	$ 2,609	$ 2,490	4.8%	$ 2,460	1.2%

(a) Reflects delivery revenue and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.
(b) Includes operating revenues from affiliates totaling $7 million for the year ended December 31, 2016 and less than $1 million in the years ended December 31, 2015 and 2014, respectively.

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BGE Natural Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [(a)]							
Retail sales	96,808	96,618	0.2%	n.m.	99,194	(2.6)%	n.m.
Transportation and other [(b)]	5,977	6,238	(4.2)%	n.m.	9,242	(32.5)%	n.m.
Total natural gas deliveries	102,785	102,856	(0.1)%	n.m.	108,436	(5.1)%	n.m.

Number of Gas Customers	As of December 31, 2016	2015	2014
Residential	623,647	616,994	609,626
Commercial & industrial	44,255	44,119	44,200
Total	667,902	661,113	653,826

Natural Gas revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [(a)]					
Retail sales	$ 593	$ 607	(2.3)%	$ 622	(2.4)%
Transportation and other [(b)]	31	38	(18.4)%	83	(54.2)%
Total natural gas revenues [(c)]	$ 624	$ 645	(3.3)%	$ 705	(8.5)%

(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 5,977 mmcfs ($23 million), 6,238 mmcfs ($35 million), and 9,242 mmcfs ($72 million) for the years ended 2016, 2015 and 2014, respectively.
(c) Includes operating revenues from affiliates totaling $14 million, $14 million, and $25 million for the years ended 2016, 2015 and 2014, respectively.

Results of Operations PHI

PHI s results of operations include the results of its three reportable segments, Pepco, DPL and ACE for all periods presented below. For Predecessor reporting periods, PHI s results of operations also include the results of PES and PCI. See Note 26 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding PHI s reportable segments. All material intercompany accounts and transactions have been eliminated in consolidation. A separate specific discussion of the results of operations for Pepco, DPL and ACE is presented elsewhere in this report.

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As a result of the PHI Merger, the following consolidated financial results present two separate reporting periods for 2016. The Predecessor reporting periods represent PHI s results of operations for the period of January 1, 2016 to March 23, 2016 and the years ended December 31, 2015 and 2014. The Successor reporting period represents PHI s results of operations for the period of March 24, 2016 to December 31, 2016. All amounts presented below are before the impact of income taxes, except as noted.

	Successor	*Predecessor*		
	March 24 to December 31, 2016	**January 1 to March 23, 2016**	**For the Years Ended December 31, 2015**	**2014**
Operating revenues	$ 3,643	$ 1,153	$ 4,935	$ 4,808
Purchased power and fuel	1,447	497	2,073	2,057
Revenues net of purchased power and fuel expense [(a)]	2,196	656	2,862	2,751
Other operating expenses				
Operating and maintenance	1,233	294	1,156	1,183
Depreciation, amortization and accretion	515	152	624	526
Taxes other than income	354	105	455	437
Total other operating expenses	2,102	551	2,235	2,146
(Loss) gain on sales of assets	(1)		46	
Operating income	93	105	673	605
Other income and (deductions)				
Interest expense, net	(195)	(65)	(280)	(269)
Other, net	44	(4)	88	44
Total other income and (deductions)	(151)	(69)	(192)	(225)
(Loss) Income before income taxes	(58)	36	481	380
Income taxes	3	17	163	138
Net (loss) income from continuing operations	(61)	19	318	242
Net income from discontinued operations			9	
Net (loss) income attributable to membership interest/common shareholders	$ (61)	$ 19	$ 327	$ 242

(a) PHI evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. PHI believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. PHI has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Successor Period of March 24, 2016 to December 31, 2016

PHI s net loss attributable to membership interest for the Successor period of March 24, 2016 to December 31, 2016 was $61 million. There were no significant changes in the underlying trends affecting PHI s results of operations during the Successor period March 24, 2016 to December 31, 2016 except for the pre-tax recording of $392 million of non-recurring merger-related costs including merger integration and merger commitments within Operating and maintenance expense. For more information on 2016 versus 2015 results please refer to Results of Operations for Pepco, DPL and ACE.

PHI s effective income tax rate for the period of March 24, 2016 to December 31, 2016 was (5.2)%. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period of January 1, 2016 to March 23, 2016

PHI s net income attributable to membership interest 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 results of 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 period of January 1, 2016 to March 23, 2016 was 47.2%. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Predecessor Period Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

PHI s net income attributable to common shareholders was $327 million for the year ended December 31, 2015 as compared to $242 million for the year ended December 31, 2014.

Revenues Net of Purchased Power and Fuel Expense

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed above, increased by $111 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The increase is attributable to the following factors:

Increase of $90 million at Pepco primarily related to electric distribution revenue increases totaling $46 million due to electric distribution base rate increases in the District of Columbia effective April 2014 and in Maryland effective July 2014 and customer growth, $34 million in required regulatory programs primarily due to EmPower Maryland rate increases effective February 2015 and 2014, and $10 million higher transmission revenue due to higher rates effective June 1, 2015 and June 1, 2014.

Increase of $26 million at DPL primarily related to electric distribution revenue increases totaling $7 million due to higher weather-related sales and customer growth, $17 million in required regulatory programs primarily due to EmPower Maryland rate increases effective February 2015 and 2014, and $7 million higher transmission revenue due to higher rates effective June 1, 2015 and June 1, 2014, partially offset by lower natural gas distribution revenues totaling $5 million due to milder weather.

Increase of $41 million at ACE primarily related to electric distribution revenue increases totaling $26 million due to an electric distribution rate increase effective September 2014 and higher weather-related sales and $15 million in required regulatory programs.

Decrease of $47 million at PES primarily related to lower energy efficiency construction activity in 2015.

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Operating and Maintenance Expense

Operating and maintenance expense decreased by $27 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The decrease is attributable to the following factors:

- Increase of $107 million at Pepco, DPL and ACE primarily due to higher labor, contracting and material costs related to the implementation of a new customer information system in 2015, increased bad debt expense, higher tree-trimming and system maintenance costs, higher customer service costs, and higher environmental remediation costs.

- Decrease of $118 million at PES primarily due to 2014 impairment losses associated with its combined heat and power thermal generating facilities and operations in Atlantic City.

- Decrease of $15 million at Corporate due primarily to lower Merger-related transaction and integration costs.

Depreciation, Amortization and Accretion Expense

Depreciation, amortization and accretion expense increased by $98 million primarily due to an increase of $48 million associated with EmPower Maryland surcharge rate increases effective February 2015 and February 2014, higher depreciation of $23 million due to on-going capital expenditures at Pepco, DPL, and ACE, an increase of $15 million in the amortization of stranded costs, primarily as the result of higher revenue due to a rate increase effective October 2014 for the ACE Market Transition Tax and an increase of $10 million in amortization of software, primarily related to the implementation of a new customer information system.

Taxes Other Than Income

Taxes other than income increased by $18 million primarily due to higher property taxes related to an increase in assets.

(Loss) gain on Sale of Assets

(Loss) gain on sale of assets increased by $46 million due to 2015 gains recorded at Pepco associated with the sale of unimproved land, held as non-utility property.

Interest Expense, Net

Interest expense increased by $11 million due to higher long-term and short-term debt.

Other, Net

Other, net increased by $44 million due to $33 million of interest income on uncertain tax positions from the PHI Global Tax Settlement and an increase in income of $15 million due to an increase in the fair value of the derivative related to preferred stock.

Effective Income Tax Rate

PHI s effective income tax rates for the years ended December 31, 2015 and December 31, 2014 were 33.9% and 36.3%, respectively. See Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

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Results of Operations Pepco

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 2,186	$ 2,129	$ 57	$ 2,055	$ 74
Purchased power expense	706	719	13	735	16
Revenues net of purchased power expense [(a)]	1,480	1,410	70	1,320	90
Other operating expenses					
Operating and maintenance	642	439	(203)	390	(49)
Depreciation and amortization	295	256	(39)	212	(44)
Taxes other than income	377	376	(1)	369	(7)
Total other operating expenses	1,314	1,071	(243)	971	(100)
Gain on sales of assets	8	46	(38)		46
Operating income	174	385	(211)	349	36
Other income and (deductions)					
Interest expense, net	(127)	(124)	(3)	(115)	(9)
Other, net	36	28	8	30	(2)
Total other income and (deductions)	(91)	(96)	5	(85)	(11)
Income before income taxes	83	289	(206)	264	25
Income taxes	41	102	61	93	(9)
Net income attributable to common shareholder	$ 42	$ 187	$ (145)	$ 171	$ 16

(a) Pepco evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. Pepco believes revenue net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Pepco has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. Pepco s net income attributable to common shareholder for the year ended December 31, 2016, was lower than the same period in 2015, primarily due to an increase in Operating and maintenance expense due to merger-related costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The increase in net income attributable to common shareholder was driven primarily by an increase in gains recorded from the sale of certain Pepco properties in 2015 and higher Operating revenues net of purchased power expense resulting from customer growth and electric distribution base rate increases in 2014 in the District of Columbia and Maryland, partially offset by an increase in Operating and maintenance expense primarily due to the implementation of a new customer information system and higher maintenance expense.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to Pepco s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that Pepco receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

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Electric revenues and purchased power expense are also affected by fluctuations in participation in the Customer Choice Program. All Pepco customers have the choice to purchase electricity from competitive electric generation suppliers. The customers choice of supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the years ended December 31, 2016, 2015, and 2014 respectively , consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	65%	65%	65%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	176,372	21%	173,222	21%	179,524	22%

Retail deliveries purchased from competitive electric generation suppliers represented 73% of Pepco s retail kWh sales to the District of Columbia customers and 59% of Pepco s retail kWh sales to Maryland customers for the year ended December 31, 2016 ; 71% of Pepco s retail kWh sales to the District of Columbia customers and 60% of Pepco s retail kWh sales to Maryland customers for the year ended December 31, 2015; and 73% of Pepco s retail kWh sales to the District of Columbia customers and 59% of Pepco s retail kWh sales to Maryland customers for year ended December 31, 2014.

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 years ended December 31, 2016 and 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Volume	$ 15	$ 24
Pricing distribution revenues	5	20
Regulatory required programs	48	34
Transmission revenues	(1)	10
Other	3	2
Total increase	$ 70	$ 90

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.

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 years ended December 31, 2016 and December 31, 2015 compared to same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	3,624	3,657	3,887	(0.9)%	(6.8)%
Cooling Degree-Days	1,936	1,936	1,626	%	19.1%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**2015 vs. Normal**
Heating Degree-Days	3,657	4,017	3,914	(9.0)%	(6.6)%
Cooling Degree-Days	1,936	1,662	1,614	16.5%	20.0%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015 primarily reflects the impact of moderate economic and customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015 compared to the same period in 2014 primarily reflects the impact of moderate economic and customer growth.

Pricing Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers in Maryland that became effective in November 2016. The increase in distribution revenue for the year ended December 31, 2015 compared to the same period in

2014 was primarily due to the impact of the new electric distribution rates charged to customers in the District of Columbia effective April 2014 and in Maryland effective July 2014. See Note 3 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 operating and maintenance expense discussion below for additional information on included programs.

Transmission Revenues. 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. Transmission revenue decreased for the year ended December 31, 2016 compared to the same period in 2015 due to lower revenue related to the MAPP abandonment recovery period that ended in March 2016, partially offset by higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses. Transmission revenue increased for the year ended December 31, 2015 compared to the same period in 2014 due to higher rates effective June 1, 2015 and June 1, 2014 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE challenges in 2015.

Operating and Maintenance Expense

	Year Ended December 31,		Increase (Decrease) 2016 vs.	Year Ended December 31,		Increase (Decrease) 2015 vs.
	2016	2015	2015	2015	2014	2014
Operating and maintenance expense baseline	$ 631	$ 427	$ 204	$ 427	$ 379	$ 48
Operating and maintenance expense regulatory required programs(a)	11	12	(1)	12	11	1
Total operating and maintenance expense	$ 642	$ 439	$ 203	$ 439	$ 390	$ 49

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 7	$ 26
Storm-related costs	6	(3)
Pension and non-pension postretirement benefits expense		4
Remeasurement of AMI related regulatory asset	7	
Deferral of billing system transition costs to regulatory asset	(7)	
Deferral of merger-related costs to regulatory asset	(11)	
Uncollectible accounts expense provision	8	4
BSC and PHISCO allocations [(a)]	53	15
Merger commitments [(b)]	126	
Write-off of construction work in progress [(c)]	13	
Other	2	2
	204	48
Regulatory required programs		
Purchased power administrative costs	(1)	1
	(1)	1
Total increase	$ 203	$ 49

(a) Primarily related to merger severance and compensation costs for the year ended December 31, 2016 compared to the same period in 2015.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.
(c) Primarily resulting from a review of capital projects during the fourth quarter of 2016.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense [(a)]	$ 11	$ 10
Regulatory asset amortization [(b)]	28	34

Total increase	$	39	$	44

(a) Depreciation expense increased primarily due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2016, partially offset by lower amortization of MAPP abandonment costs and for the year ended December 31, 2015 compared to the same period in 2014 due to an EmPower Maryland surcharge rate increase effective February 2015.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher utility taxes that are collected and passed through by Pepco, partially offset by lower property taxes in Maryland. Taxes other than income for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher property taxes in Maryland.

Gain on Sales of Assets

Gain on Sale of Assets for the year ended December 31, 2016 compared to the same period in 2015 decreased primarily due to higher gains recorded in 2015 at Pepco associated with the sale of land held as non-utility property. Gain on sale of assets for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to 2015 gains recorded at Pepco associated with the sale of land.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by an increase in capitalized AFUDC debt. Interest expense, net for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher long-term debt interest expense.

Other, Net

Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity. Other, net for the year ended December 31, 2015 compared to the same period in 2014 decreased primarily due to gains recorded in 2014 associated with condemnation awards for certain transmission property, partially offset by higher income from AFUDC equity.

Effective Income Tax Rate

Pepco s effective income tax rates for the years ended December 31, 2016, 2015, and 2014 were 49.4%, 35.3%, and 35.2%, respectively. See Note 15 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 $31 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

Pepco Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	8,372	8,452	(0.9)%	1.6%	7,854	7.6%	2.2%
Small commercial & industrial	1,459	1,471	(0.8)%	0.8%	1,747	(15.8)%	1.4%
Large commercial & industrial	15,559	15,351	1.4%	1.0%	15,410	(0.4)%	1.2%
Public authorities & electric railroads	724	714	1.4%	%	740	(3.5)%	%
Total retail deliveries	26,114	25,988	0.5%	1.1%	25,751	0.9%	1.5%

As of December 31,

Number of Electric Customers	**2016**	**2015**	**2014**
Residential	780,652	767,392	740,102
Small commercial & industrial	53,529	53,838	54,176
Large commercial & industrial	21,391	20,976	20,649
Public authorities & electric railroads	130	129	124
Total	855,702	842,335	815,051

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Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$ 1,000	$ 970	3.1%	$ 889	9.1%
Small commercial & industrial	150	153	(2)%	174	(12.1)%
Large commercial & industrial	803	777	3.3%	766	1.4%
Public authorities & electric railroads	32	30	6.7%	30	%
Total retail	1,985	1,930	2.8%	1,859	3.8%
Other revenue [b]	201	199	1.0%	196	1.5%
Total electric revenue [c]	$ 2,186	$ 2,129	2.7%	$ 2,055	3.6%

(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 $5 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Results of Operations DPL

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 1,277	$ 1,302	$ (25)	$ 1,282	$ 20
Purchased power and fuel	583	634	51	640	6
Revenues net of purchased power and fuel expense [a]	694	668	26	642	26
Other operating expenses					
Operating and maintenance	441	304	(137)	267	(37)
Depreciation, amortization and accretion	157	148	(9)	122	(26)
Taxes other than income	55	51	(4)	46	(5)
Total other operating expenses	653	503	(150)	435	(68)
Gain on sales of assets	9		9		

Operating income	50	165	(115)	207	(42)
Other income and (deductions)					
Interest expense, net	(50)	(50)		(48)	(2)
Other, net	13	10	3	10	
Total other income and (deductions)	(37)	(40)	3	(38)	(2)
Income before income taxes	13	125	(112)	169	(44)
Income taxes	22	49	27	65	16
Net (loss) income attributable to common shareholder	$ (9)	$ 76	$ (85)	$ 104	$ (28)

(a) DPL evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. DPL believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements because they provide information that can be used to evaluate its operational performance. DPL has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense and Revenue net of fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to the implementation of a new customer information system, higher bad debt expense and higher tree trimming and system maintenance costs, partially offset by higher Operating revenues net of purchased power expense resulting from customer growth and higher transmission revenue.

Revenues Net of Purchased Power and Fuel Expense

Operating revenues include revenue from the distribution and supply of electricity to DPL s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that DPL receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All DPL customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customers choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the years ended December 31, 2016, 2015, and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	51%	51%	53%
Natural Gas	28%	31%	31%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	78,994	15.2%	77,603	15.1%	78,153	15.3%
Natural Gas	156	0.1%	159	0.1%	157	0.1%

Retail deliveries purchased from competitive electric generation suppliers represented 53% of DPL s retail kWh sales to Delaware customers and 48% of DPL retail kWh sales to Maryland customers for the year ended December 31, 2016; 53% of DPL s retail kWh sales to Delaware customers and 47% of DPL s retail kWh sales to Maryland customers for the year ended December 31, 2015; and 56% of DPL s retail kWh sales to Delaware customers and 49% of DPL s retail kWh sales to Maryland customers for the year ended December 31, 2014.

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.

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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 revenues 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 years ended December 31, 2016 and 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	2016 vs. 2015 Increase (Decrease)			2015 vs. 2014 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$	$	$	$ 3	$ (5)	$ (2)
Volume	2	2	4	3		3
Pricing distribution revenues	2	1	3			
Regulatory required programs	12		12	17		17
Transmission revenues	8		8	7		7
Other	(1)		(1)	1		1
Increase (Decrease) in revenue net of purchased power expense	$ 23	$ 3	$ 26	$ 31	$ (5)	$ 26

Revenue Decoupling. DPL s results historically have been seasonal, generally producing higher revenue and income in the warmest and coldest periods of the year. For retail customers of DPL in Maryland, revenues are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) for retail customers was implemented that provides for a fixed distribution charge per customer. The BSA has the effect of decoupling the distribution revenue recognized in a reporting period from the amount of power delivered during the period. As a result, the only factors that will cause distribution revenue from customers in Maryland to fluctuate from period to period are changes in the number of customers and changes in the approved distribution charge per customer. A modified fixed variable rate design, which would provide for a charge not tied to a customer s volumetric consumption of electricity or natural gas, has been proposed for DPL electricity and natural gas customers in Delaware. Changes in customer usage (due to weather conditions, energy prices, energy efficiency programs or other reasons) from period to period have no impact on reported distribution revenue for customers to whom the BSA applies.

In accounting for the BSA in Maryland, a Revenue Decoupling Adjustment is recorded representing either (i) a positive adjustment equal to the amount by which revenue from Maryland retail

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distribution sales falls short of the revenue that DPL is entitled to earn based on the approved distribution charge per customer or (ii) a negative adjustment equal to the amount by which revenue from such distribution sales exceeds the revenue that DPL is entitled to earn based on the approved distribution charge per customer.

Weather. The demand for electricity and gas in areas not subject to the BSA is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as favorable weather conditions because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. During the year ended December 31, 2016 compared to the same period in 2015, weather was not a significant impact. During the year ended December 31, 2015 compared to the same period in 2014, operating revenues net of purchased power and fuel expense was higher due to the impact of favorable spring and summer weather conditions in DPL s Delaware electric service territory and lower due to the impact of warmer weather during the fourth quarter of 2015, as compared to 2014, in DPL s natural gas service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 20-year period in DPL s electric service territory and a 30-year period in DPL s gas service territory. The changes in heating and cooling degree days in DPL s service territory for the years ended December 31, 2016 and December 31, 2015 compared to same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	4,319	4,421	4,572	(2.3)%	(5.5)%
Cooling Degree-Days	1,453	1,328	1,188	9.4%	22.3%

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2015**	**2014**	**Normal**	**2015 vs. 2014**	**2015 vs. Normal**
Heating Degree-Days	4,421	4,724	4,592	(6.4)%	(3.7)%
Cooling Degree-Days	1,328	1,139	1,184	16.6%	12.2%

Volume. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects the impact of moderate economic and customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015 compared to the same period in 2014, primarily reflects the impact of moderate economic and customer growth.

Pricing Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution and natural gas rates charged to customers that became effective in July 2016. See Note 3 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 operating and maintenance expense discussion below for additional information on included programs.

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Transmission Revenues. 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. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses, partially offset by lower revenue related to the MAPP abandonment recovery period that ended in March 2016. Transmission revenue increased for the year ended December 31, 2015 compared to the same period in 2014 due to higher rates effective June 1, 2015 and June 1, 2014 related to increases in transmission plant investment and operating expenses, partially offset by the establishment of a reserve related to the FERC ROE challenges in 2015.

Operating and Maintenance Expense

	Year Ended December 31,		Increase	Year Ended December 31,		Increase
	2016	2015	(Decrease)	2015	2014	(Decrease)
Operating and maintenance expense baseline	$ 425	$ 289	$ 136	$ 289	$ 256	$ 33
Operating and maintenance expense regulatory required programs[(a)]	16	15	1	15	11	4
Total operating and maintenance expense	$ 441	$ 304	$ 137	$ 304	$ 267	$ 37

(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 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 1	$ 5
Pension and non-pension postretirement benefits expense	1	3
Storm-related costs	5	1
Remeasurement of AMI-related regulatory asset	1	
Deferral of billing system transition costs to regulatory asset	(2)	
Deferral of merger-related costs to regulatory asset	(4)	
Uncollectible accounts expense provision	3	6
BSC and PHISCO allocations [(a)]	34	13
Merger commitments [(b)]	86	
Write-off of construction work in progress	4	2
Other	7	3

		136		33
Regulatory required programs				
Purchased power administrative costs		1		4
Total increase	$	137	$	37

(a) Primarily related to merger severance and compensation costs for the year ended December 31, 2016 compared to the same period in 2015.

(b) Primarily related to merger-related commitments for energy efficiency programs, customer rate credits and charitable contributions.

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Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense [(a)]	$ 7	$ 9
Regulatory asset amortization [(b)]	3	14
Delaware renewable energy portfolio standards deferral	(1)	3
Total increase	$ 9	$ 26

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization increased for the year ended December 31, 2016 compared to the same period in 2015 primarily due to an EmPower Maryland surcharge rate increase effective February 2016, partially offset by lower amortization of MAPP abandonment costs and for the year ended December 31, 2015 compared to the same period in 2014 due to an EmPower Maryland surcharge rate increase effective February 2015.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher property taxes in Maryland related to higher property assessments and rate increases. Taxes other than income for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher property taxes related to an increase in assets.

Gain on Sales of Assets

Gain on Sale of Assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at DPL associated with the sale of land held as non-utility property.

Interest Expense, Net

Interest expense, net for the year ended December 31, 2016 compared to the same period in 2015 remained constant. Interest expense, net for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to higher long-term debt interest expense.

Other, Net

Other, net for the year ended December 31, 2016, compared to the same period in 2015 increased primarily due to higher income from AFUDC equity. Other, net for the year ended December 31, 2015, compared to the same period in 2014 remained constant.

Effective Income Tax Rate

DPL s effective income tax rates for the years ended December 31, 2016, 2015, and 2014 were 169.2%, 39.2%, and 38.5%, respectively. See Note 15 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, DPL recorded an after-tax charge of $23 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

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DPL Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	5,181	5,337	(2.9)%	1.0%	5,188	2.9%	0.9%
Small commercial & industrial	2,290	2,311	(0.9)%	0.7%	2,147	7.6%	0.5%
Large commercial & industrial	4,623	4,781	(3.3)%	1.0%	5,030	(5.0)%	0.5%
Public authorities & electric railroads	46	45	2.2%	%	47	(4.3)%	%
Total retail deliveries	12,140	12,474	(2.7)%	0.9%	12,412	0.5%	0.7%

Number of Electric Customers	As of December 31, 2016	2015	2014
Residential	456,181	453,145	448,615
Small commercial & industrial	60,173	59,714	39,246
Large commercial & industrial	1,411	1,410	21,388
Public authorities & electric railroads	643	643	642
Total	518,408	514,912	509,891

Electric Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [(a)]					
Residential	$ 668	$ 681	(1.9)%	$ 653	4.3%
Small commercial & industrial	187	192	(2.6)%	160	20.0%
Large commercial & industrial	98	101	(3.0)%	108	(6.5)%
Public authorities & electric railroads	13	12	8.3%	12	%
Total retail	966	986	(2.0)%	933	5.7%
Other revenue [(b)]	163	152	7.2%	155	(1.9)%
Total electric revenue [(c)]	$ 1,129	$ 1,138	(0.8)%	$ 1,088	4.6%

(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 $7 million, $6 million and $7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

DPL Gas Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in mmcf)	**2016**	**2015**	**% Change 2016 vs. 2015**	**Weather Normal % change**	**2014**	**% Change 2015 vs. 2014**	**Weather Normal % change**
Retail Deliveries							
Residential	14,087	13,816	2.0%	(5.0)%	14,613	(5.5)%	(2.4)%
Transportation & other	5,455	6,193	(11.9)%	(1.4)%	6,418	(3.5)%	%
Total gas deliveries	19,542	20,009	(2.3)%	(4.1)%	21,031	(4.9)%	(1.6)%

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Number of Gas Customers	As of December 31, 2016	2015	2014
Residential	120,951	119,771	117,880
Commercial & industrial	9,801	9,712	9,615
Transportation & other	156	159	157
Total	130,908	129,642	127,652

Gas Revenue	2016	2015	% Change 2016 vs. 2015	2014	% Change 2015 vs. 2014
Retail Sales [(a)]					
Retail sales	$ 127	$ 143	(11.2)%	$ 165	(13.3)%
Transportation & other [(b)]	21	21	%	29	(27.6)%
Total gas revenues	$ 148	$ 164	(9.8)%	$ 194	(15.5)%

(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.

Results of Operations ACE

	2016	2015	Favorable (unfavorable) 2016 vs. 2015 variance	2014	Favorable (unfavorable) 2015 vs. 2014 variance
Operating revenues	$ 1,257	$ 1,295	$ (38)	$ 1,210	$ 85
Purchased power expense	651	708	57	664	(44)
Revenues net of purchased power expense [(a)]	606	587	19	546	41
Other operating expenses					
Operating and maintenance	428	271	(157)	250	(21)
Depreciation, amortization and accretion	165	175	10	155	(20)
Taxes other than income	7	7		4	(3)
Total other operating expenses	600	453	(147)	409	(44)

Gain on sales of assets	1		1		
Operating income	7	134	(127)	137	(3)
Other income and (deductions)					
Interest expense, net	(62)	(64)	2	(64)	
Other, net	9	3	6	3	
Total other income and (deductions)	(53)	(61)	8	(61)	
(Loss) income before income taxes	(46)	73	(119)	76	(3)
Income taxes	(4)	33	37	30	(3)
Net (loss) income attributable to common shareholder	$ (42)	$ 40	$ (82)	$ 46	$ (6)

(a) ACE evaluates its operating performance using the measure of revenue net of purchased power expense for electric sales. ACE believes Revenue net of purchased power expense is a useful measurement of its performance because it provides information that can be used to evaluate its operational performance. ACE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, Revenue net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income Attributable to Common Shareholder

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to merger-related costs.

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014. The decrease in net income attributable to common shareholder was driven primarily by an increase in Operating and maintenance expense primarily due to the implementation of a new customer information system and higher storm restoration costs, partially offset by higher Operating revenues net of purchased power expense resulting from an electric distribution base rate increase in 2014 in New Jersey.

Revenues Net of Purchased Power Expense

Operating revenues include revenue from the distribution and supply of electricity to ACE s customers within its service territories at regulated rates. Operating revenues also include transmission service revenue that ACE receives as a transmission owner from PJM at rates regulated by FERC. Transmission rates are updated annually based on a FERC-approved formula methodology.

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 years ended December 31, 2016, 2015, and 2014, consisted of the following:

	For the Years Ended December 31,		
	2016	2015	2014
Electric	47%	45%	51%

Retail customers purchasing electric generation from competitive electric generation suppliers at December 31, 2016, 2015, and 2014 consisted of the following:

	December 31, 2016		December 31, 2015		December 31, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	94,562	17%	78,299	14%	86,780	16%

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.

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Purchased power expense consists of the cost of electricity purchased by ACE to fulfill its default electricity supply obligation and, as such, is recoverable from customers in accordance with the terms of public service commission orders.

The changes in ACE s operating revenues net of purchased power expense for the years ended December 31, 2016 and 2015 compared to the same periods in 2015 and 2014, respectively, consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Weather	$ (3)	$ 9
Volume	1	2
Pricing distribution revenues	14	18
Regulatory required programs	(15)	15
Transmission revenues	23	
Other	(1)	(3)
Increase in revenue net of purchased power expense	$ 19	$ 41

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 year ended December 31, 2016 compared to the same period in 2015, operating revenues net of purchased power and fuel expense was lower due to the impact of unfavorable winter weather conditions in ACE s service territory. During the year ended December 31, 2015 compared to the same period in 2014, operating revenues net of purchased power and fuel expense was higher due to the impact of favorable spring and summer 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 years ended December 31, 2016 and December 31, 2015 compared to same periods in 2015 and 2014, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	**2016**	**2015**	**Normal**	**2016 vs. 2015**	**2016 vs. Normal**
Heating Degree-Days	4,487	4,671	4,768	(3.9)%	(5.9)%
Cooling Degree-Days	1,303	1,259	1,093	3.5%	19.2%

Heating and Cooling Degree-Days	For the Years Ended December 31, 2015	2014	Normal	% Change 2015 vs. 2014	2015 vs. Normal
Heating Degree-Days	4,671	5,192	4,795	(10.0)%	(2.6)%
Cooling Degree-Days	1,259	819	1,076	53.7%	17.0%

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Volume. The decrease in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2016 compared to the same period in 2015, primarily reflects lower average customer usage, partially offset by the impact of moderate economic and customer growth. The increase in operating revenues net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the year ended December 31, 2015 compared to the same period in 2014, primarily reflects the impact of moderate economic and customer growth.

Pricing Distribution Revenues. The increase in electric operating revenues net of purchased power expense as a result of pricing for the year ended December 31, 2016 compared to the same period in 2015 was primarily due to the impact of the new electric distribution rates charged to customers that became effective in August 2016. The increase in distribution revenue for the year ended December 31, 2015 compared to the same period in 2014 was primarily due to the impact of the new electric distribution rates charged to customers that became effective September 2014. See Note 3 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 Revenues. 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. Transmission revenue increased for the year ended December 31, 2016 compared to the same period in 2015 due to higher rates effective June 1, 2016 and June 1, 2015 related to increases in transmission plant investment and operating expenses. Transmission revenue remained constant for the year ended December 31, 2015 compared to the same period in 2014 due to higher rates effective June 1, 2015 and June 1, 2014 related to increases in transmission plant investment and operating expenses, offset by the establishment of a reserve related to the FERC ROE challenges in 2015.

Operating and Maintenance Expense

	Year Ended December 31, 2016	Year Ended December 31, 2015	Increase (Decrease) 2016 vs. 2015	Year Ended December 31, 2015	Year Ended December 31, 2014	Increase (Decrease) 2015 vs. 2014
Operating and maintenance expense baseline	$ 424	$ 267	$ 157	$ 267	$ 243	$ 24
Operating and maintenance expense regulatory required programs (a)	4	4		4	7	(3)
Total operating and maintenance expense	$ 428	$ 271	$ 157	$ 271	$ 250	$ 21

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in Operating revenues.

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The changes in operating and maintenance expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Baseline		
Labor, other benefits, contracting and materials	$ 6	$ 5
Pension and non-pension postretirement benefits expense		1
Storm-related costs	1	6
BSC and PHISCO allocations [a]	26	17
Uncollectible accounts expense	2	
Merger commitments [b]	111	
Other	11	(5)
	157	24
Regulatory required programs		
Purchased power administrative costs		(3)
		(3)
Total increase	$ 157	$ 21

(a) Primarily related to merger severance and compensation costs for the year ended December 31, 2016 compared to the same period in 2015.
(b) Primarily related to merger-related commitments for customer rate credits and charitable contributions.

Depreciation, Amortization and Accretion Expense

The changes in depreciation, amortization and accretion expense for 2016 compared to 2015 and 2015 compared to 2014 consisted of the following:

	Increase (Decrease) 2016 vs. 2015	Increase (Decrease) 2015 vs. 2014
Depreciation expense [a]	$ 6	$ 4
Regulatory asset amortization [b]	(16)	16
Total (decrease) increase	$ (10)	$ 20

(a) Depreciation expense increased due to ongoing capital expenditures.
(b) Regulatory asset amortization decreased for the year ended December 31, 2016 compared to the same period in 2015 primarily as a result of lower revenue due to a rate decrease effective October 2015 for the ACE Market Transition charge tax. Regulatory asset amortization increased for the year ended December 31, 2015 compared to the same period in 2014 as a result of higher revenue due to a rate increase effective October 2014 for the ACE Market Transition charge tax.

Taxes Other Than Income

Taxes other than income for the year ended December 31, 2016 compared to the same period in 2015, remained constant. Taxes other than income for the year ended December 31, 2015 compared to the same period in 2014 increased primarily due to an increase in the New Jersey use tax.

Interest Expense, Net

Interest expense, net remained relatively consistent for the year ended December 31, 2016, compared to the same period in 2015, and the year ended December 31, 2015, compared to the same period in 2014.

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Gain on Sales of Assets

Gain on Sale of Assets for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to gains recorded in 2016 at ACE associated with the sale of property.

Other, Net

Other, net for the year ended December 31, 2016 compared to the same period in 2015 increased primarily due to higher income from AFUDC equity. Other, net for the year ended December 31, 2015 compared to the same period in 2014 remained relatively consistent.

Effective Income Tax Rate

ACE s effective income tax rates for the years ended December 31, 2016, 2015, and 2014 were 8.7%, 45.2%, and 39.5%, respectively. See Note 15 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, ACE recorded an after-tax charge of $22 million during the year ended December 31, 2016 as a result of the assessment and remeasurement of certain federal and state uncertain tax positions.

ACE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	2016	2015	% Change 2016 vs. 2015	Weather-Normal % Change	2014	% Change 2015 vs. 2014	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	4,153	4,322	(3.9)%	1.1%	4,087	5.7%	2.7%
Small commercial & industrial	1,455	1,288	13.0%	0.5%	1,217	5.8%	1.4%
Large commercial & industrial	3,402	3,594	(5.3)%	0.7%	3,699	(2.8)%	1.4%
Public authorities & electric railroads	49	45	8.9%	%	48	(6.3)%	%
Total retail deliveries	9,059	9,249	(2.1)%	0.8%	9,051	2.2%	2.0%

Number of Electric Customers	As of December 31, 2016	2015	2014
Residential	484,240	482,000	479,140
Small commercial & industrial	61,008	60,745	61,734
Large commercial & industrial	3,763	3,871	3,877
Public authorities & electric railroads	610	529	526
Total	549,621	547,145	545,277

Electric Revenue	2016	2015	2014

			% Change 2016 vs. 2015		% Change 2015 vs. 2014
Retail Sales [a]					
Residential	$ 664	$ 690	(3.8)%	$ 582	18.6%
Small commercial & industrial	183	175	4.6%	152	15.1%
Large commercial & industrial	201	213	(5.6)%	190	12.1%
Public authorities & electric railroads	13	12	8.3%	12	%
Total retail	1,061	1,090	(2.7)%	936	16.5%
Other revenue [b]	196	205	(4.4)%	274	(25.2)%
Total electric revenue [c]	$ 1,257	$ 1,295	(2.9)%	$ 1,210	7.0%

(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 $3 million, $4 million and $4 million for the years ended December 31, 2016, 2015 and 2014, 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 December 31, 2016. Exelon prior year activity is unadjusted for the effects of the PHI Merger. Due to the application of push-down accounting to the PHI entity, PHI s activity is presented in two separate reporting periods, the legacy PHI activity through March 23, 2016 (Predecessor), and PHI activity for the remainder of the period after the PHI merger date (Successor). For each of Pepco, DPL and ACE the activity presented below include its activity for the years ended December 31, 2016, 2015 and 2014. Exelon s and Generation s activity presented below includes the activity of CENG, from the integration date effective April 1, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

The Registrants operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants businesses are capital intensive and require considerable capital resources. Each Registrant s access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, the Registrants have access to unsecured revolving credit facilities with aggregate bank commitments of $9 billion. In addition, Generation has $500 million in bilateral facilities with banks which have various expirations between January 2017 and January 2019. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the Credit Matters section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO, BGE, Pepco, DPL and ACE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants debt and credit agreements.

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that sufficient funds will be available in certain minimum amounts to decommission the facility. These NRC minimum funding levels are based upon the assumption that decommissioning activities will commence after the end of the current licensed life of each unit. If a unit fails the NRC minimum funding test, then the plant s owners or parent companies would be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or

making additional cash contributions to the NDT fund to ensure sufficient funds are available. See Note 16 Asset Retirement Obligations to the Combined Notes to Consolidated Financial Statements for additional information on the NRC minimum funding requirements.

If a nuclear plant were to early retire there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT fund investments could appreciate in value. A shortfall could require Exelon to post parental guarantees for Generation s share of the obligations. However, the amount of any required guarantees will ultimately depend on the decommissioning approach adopted at each site, the associated level of costs, and the decommissioning trust fund investment performance going forward. Within two years after shutting down a plant, Generation must submit a post-shutdown decommissioning activities report (PSDAR) to the NRC that includes the planned option for decommissioning the site. When Generation files its biennial decommissioning funding status report with the NRC on March 31, 2017, as compared to previous estimates prior to the reversal of the early retirement decision, it is currently estimated that given the later commencement of decommissioning activities and a longer time period over which the NDT fund investments can appreciate in value, Quad Cities will meet the NRC minimum funding requirements. It is currently estimated that Clinton will fall below the NRC minimum funding requirements by only a small amount. As of December 31, 2016, TMI passes the NRC minimum funding test based on its current license life. However, in the event of an early retirement of TMI, the most costly estimates could require parental guarantees of up to $60 million.

Upon issuance of any required financial guarantees, each site would be able to utilize the respective NDT funds for radiological decommissioning costs, which represent the majority of the total expected decommissioning costs. However, the NRC must approve an additional exemption in order for the plant s owner(s) to utilize the NDT fund to pay for non-radiological decommissioning costs (i.e. spent fuel management and site restoration costs). If a unit does not receive this exemption, the costs would be borne by the owner(s). While the ultimate amounts may vary greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the United States Department of Energy reimbursement agreements or future litigation, across the three alternative decommissioning approaches available, if an early retirement decision is made and TMI were to fail the exemption test, Generation could incur spent fuel management and site restoration costs over the next ten years of up to $145 million, net of taxes.

Cash Flows from Operating Activities

General

Generation s cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation s future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

The Utility Registrants cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, BGE, and DPL, gas distribution services. The Utility Registrants distribution services are provided to an established and diverse base of retail customers. The Utility Registrants future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Notes 3 Regulatory Matters and 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

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The following table provides a summary of the major items affecting Exelon s cash flows from operations for the years ended December 31, 2016, 2015 and 2014:

	2016	2015	2016 vs. 2015 Variance	2014 (c)	2015 vs. 2014 Variance
Net income	$ 1,204	$ 2,250	$ (1,046)	1,820	$ 430
Add (subtract):					
Non-cash operating activities (a)	7,722	5,630	2,092	5,884	(254)
Pension and non-pension postretirement benefit contributions	(397)	(502)	105	(617)	115
Income taxes	(674)	97	(771)	(143)	240
Changes in working capital and other noncurrent assets and liabilities (b)	(275)	(264)	(11)	(806)	542
Option premiums received (paid), net	(66)	58	(124)	38	20
Collateral received (posted), net	931	347	584	(1,719)	2,066
Net cash flows provided by operations	$ 8,445	$ 7,616	$ 829	$ 4,457	$ 3,159

(a) Represents depreciation, amortization, depletion and accretion, net fair value changes related to derivatives, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges. See Note 25 Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for further detail on non-cash operating activity.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

(c) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, CENG s revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

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. The estimated impacts of the law are reflected in the projected pension contributions below.

Exelon expects to make qualified pension plan contributions of $310 million to its qualified pension plans in 2017, of which Generation, ComEd, PECO, BGE and Pepco expect to contribute $127 million, $33 million, $23 million, $38 million and $60 million, respectively. Exelon s and Generation s expected qualified pension plan contributions above include $21 million related to the legacy CENG plans that will be funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG. Exelon s non-qualified pension plans are not funded. Exelon expects to make non-qualified pension plan benefit payments of $23 million in 2017, of which Generation, ComEd, PECO, BGE and Pepco will make payments of $6 million, $1 million, $1 million, $2 million and $1 million, respectively. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants 2016 and 2015 pension contributions.

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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.

Unlike qualified pension plans, other postretirement benefit plans are not subject to statutory minimum contribution requirements and certain plans are not funded. OPEB funding generally follows accounting cost; however, Exelon s management has historically considered several factors in determining the level of contributions to its funded other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulator expectations and best assure continued recovery). Exelon expects to make other postretirement benefit plan contributions, including benefit payments related to unfunded plans, of approximately $44 million in 2017, of which Generation, ComEd, BGE and Pepco expect to contribute $12 million, $2 million, $16 million and $10 million, respectively. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for the Registrants 2016 and 2015 other postretirement benefit contributions.

See the Contractual Obligations section for management s estimated future pension and other postretirement benefits contributions.

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 in the second quarter of 2017). While the final calculation of tax, penalty 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 second quarter of 2017. While Exelon will receive a tax benefit of approximately $400 million associated with the deduction for the interest, Exelon currently expects to have 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 the second quarter of 2017 at the time Exelon files its appeal of the Tax Court decision. Exelon funded the $1.25 billion deposit with a combination of cash on hand and short-term borrowings. The deposit is reflected as a current asset and the related liabilities for the tax, penalty, and interest are included on Exelon s balance sheet as current obligations.

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.

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Cash flows provided by operations for the year ended December 31, 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [(a)]	$ 8,445	$ 7,616	$ 4,457
Generation [(a)]	4,444	4,199	1,826
ComEd	2,505	1,896	1,326
PECO	829	770	712
BGE	945	782	740
Pepco	651	373	386
DPL	310	266	268
ACE	385	256	259

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ 888	$ 264	$ 939	$ 854

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, CENG s revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

Changes in 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 2016, 2015 and 2014 were as follows:

Generation

Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on an exchange or in the OTC markets. During 2016, 2015 and 2014, Generation had net collections/(payments) of counterparty cash collateral of $923 million, $407 million and $(1,748) million, respectively, primarily due to market conditions that resulted in changes to Generation s net mark-to-market position, as well as Exelon s decision to post more cash collateral in 2014 compared to using letters of credit in 2015 to support the PHI merger financing.

During 2016, 2015 and 2014, Generation had net (payments)/collections of approximately $(66) million, $58 million, and $38 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

During 2016 and 2015, ComEd received a return of approximately $7 million of cash collateral from PJM and posted $31 million of cash collateral to PJM, respectively. During 2014, ComEd posted no cash collateral to PJM. During 2016, ComEd s collateral posted with PJM has decreased due to lower PJM billings. During 2015 ComEd s collateral posted with PJM has increased primarily due to higher RPM credit requirements and higher PJM billings resulting from increased load being served by ComEd as a result of City of Chicago customers switching back to ComEd.

For further discussion regarding changes in non-cash operating activities, please refer to Note 25 Supplemental Financial Information of the Combined Notes to the Financial Statements.

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Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2016, 2015, and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [(a)]	$ (15,503)	$ (7,822)	$ (4,599)
Generation [(a)]	(3,851)	(4,069)	(1,767)
ComEd	(2,685)	(2,362)	(1,655)
PECO	(798)	(588)	(649)
BGE	(910)	(675)	(622)
Pepco	(647)	(477)	(560)
DPL	(336)	(345)	(358)
ACE	(309)	(306)	(224)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, CENG s revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
PHI	$ (1,030)	$ (343)	$ (1,161)	$ (1,226)

Significant investing cash flow impacts for the Registrants for 2016, 2015 and 2014 were as follows:

Exelon

During 2016, Exelon had expenditures of $6.6 billion, $235 million and $58 million relating to the acquisitions of PHI, ConEdison Solutions and the pending acquisition of the FitzPatrick facility, respectively.

During 2016 and 2014, Exelon had proceeds of $360 million and $335 million as a result of early termination of direct financing leases.

During 2014, Exelon had proceeds of $1.7 billion from the sale of certain long lived assets in order to finance a portion of the merger with PHI.

Generation

During 2016, Generation had expenditures of, $235 million and $58 million relating to the acquisitions of ConEdison Solutions and the pending acquisition of the FitzPatrick facility, respectively.

During 2014, Generation had proceeds of $1.7 billion from the sale of certain long lived assets in order to finance a portion of the merger with PHI.

Capital Expenditure Spending

Generation

Generation has entered into several agreements to acquire equity interests in privately held development stage entities which develop energy-related technology. The agreements contain a series of scheduled investment commitments, including in-kind services contributions. There are approximately $39 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further details of Generation s equity interests.

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Capital expenditures by Registrant for the year ended December 31, 2016, 2015, and 2014 and projected amounts for 2017 are as follows:

	Projected 2017 [(a)]	2016	2015	2014
Exelon [(b)(d)]	$ 8,250	$ 8,553	$ 7,624	$ 6,077
Generation [(b)]	2,650	3,078	3,841	3,012
ComEd [(c)]	2,200	2,734	2,398	1,689
PECO	775	686	601	661
BGE	925	934	719	620
Pepco	625	586	544	567
DPL	375	349	352	352
ACE	300	311	300	225

		Successor	*Predecessor*		
	Projected 2017 [(a)]	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI [(e)]	$ 1,375	$ 1,008	$ 273	$ 1,230	$ 1,223

(a) Total projected capital expenditures do not include adjustments for non-cash activity.
(b) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, CENG s revenues net of purchased power and fuel expenses are included on a fully consolidated basis.
(c) The capital expenditures and 2017 projections include $281 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.
(d) Includes corporate operations, BSC, and PHISCO rounded to the nearest $25 million.
(e) Includes PHISCO rounded to the nearest $25 million.

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

Generation

Approximately 35% and 23% of the projected 2017 capital expenditures at Generation are for the acquisition of nuclear fuel and the construction of new natural gas plants, respectively, with the remaining amounts reflecting investment in renewable energy and additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Approximately 89% of the projected 2017 capital expenditures at ComEd and 100% of the projected 2017 capital expenditures at PECO, BGE, Pepco, DPL, and ACE 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 the capital expenditure for continuing projects, ComEd s total expenditures include smart grid/smart meter technology required under EIMA.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In

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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 2017 capital expenditures above reflect capital spending for remediation to be completed through 2018. Pepco, DPL and ACE have substantially completed their assessments and thus do not expect significant capital expenditures related to this guidance in 2017.

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 3 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 year ended December 31, 2016, 2015, and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [(a)]	$ 1,191	$ 4,830	$ 411
Generation [(a)]	(734)	(479)	(537)
ComEd	169	467	359
PECO	(263)	83	(250)
BGE	(21)	(162)	(85)
Pepco		103	171
DPL	67	80	92
ACE	22	51	(36)

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, CENG s revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
PHI	$ (7)	$ 372	$ 233	$ 363

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Debt

See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants debt issuances and retirements. Debt activity for 2016, 2015 and 2014 by Registrant was as follows:

During the year ended December 31, 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[(a)]	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 [(b)]	LIBOR + 1.25%	November 17, 2017	$ 98	Albany Green Energy biomass generation development
Generation	Energy Efficiency Project Financing [(b)]	3.17%	December 31, 2017	$ 16	Funding to install energy conservation measures in Brooklyn, NY
Generation	Energy Efficiency Project Financing [(b)]	3.90%	January 31, 2018	$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project
Generation	Energy Efficiency Project Financing [(b)]	3.52%	April 30, 2018	$ 14	Funding to install energy conservation measures for the Smithsonian Zoo project
Generation		3.93%		$ 150	

	SolGen Nonrecourse Debt [(a)]		September 30, 2036			General corporate purposes
Generation	Energy Efficiency Project Financing [(b)]	3.46%	October 1, 2018	$	36	Funding to install energy conservation measures or the Marine Corps Logistics Base project

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing (b)	2.61%	September 30, 2018	$ 4	Funding to install energy conservation measures for the Pensacola 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
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
PECO	First Mortgage Bonds	1.70%	September 15, 2021	$ 300	Refinance maturing mortgage bonds
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
Pepco	Energy Efficiency Project Financing (b)	3.30%	December 15, 2017	$ 4	Funding to install energy conservation measures for the DOE Germantown project
DPL	First Mortgage Bonds	4.15%	May 15, 2045	$ 175	Refinance maturing mortgage bonds, repay commercial paper and general corporate purposes

(a) See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

(b) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

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During the year ended December 31, 2015, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes	1.55%	June 9, 2017	$ 550	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	2.85%	June 15, 2020	$ 900	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	$ 1,250	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	$ 500	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	$ 1,000	Finance a portion of the pending merger with PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 111	Procurement of software licenses
Generation	Senior Unsecured Notes	2.95%	January 15, 2020	$ 750	Fund the optional redemption of Exelon s $550 million, 4.550% Senior Notes and for general corporate purposes
Generation	AVSR DOE Nonrecourse Debt	2.29 - 2.96%	January 5, 2037	$ 39	Antelope Valley solar development
Generation	Energy Efficiency Project Financing	3.71%	July 31, 2017	$ 42	Funding to install energy conservation measures in Coleman, Florida

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Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.55%	November 15, 2016	$ 19	Funding to install energy conservation measures in Frederick, Maryland
Generation	Tax Exempt Pollution Control Revenue Bonds	2.50 - 2.70%	2019 - 2020	$ 435	General corporate purposes
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 100	Albany Green Energy biomass generation development
Generation	Nuclear Fuel Purchase Contract	3.15%	September 30, 2020	$ 57	Procurement of uranium
ComEd	First Mortgage Bonds, Series 118	3.70%	March 1, 2045	$ 400	Refinance maturing mortgage bonds, repay a portion of ComEd s outstanding commercial paper obligations and for general corporate purposes
ComEd	First Mortgage Bonds, Series 119	4.35%	November 15, 2045	$ 450	Repay a portion of ComEd s outstanding commercial paper obligations and for general corporate purposes
PECO	First and Refunding Mortgage Bonds	3.15%	October 15, 2025	$ 350	General corporate purposes
Pepco	First Mortgage Bonds	4.15%	March 15, 2043	$ 200	Repay outstanding commercial paper obligations and general corporate purposes
DPL	First Mortgage Bonds	4.15%	May 15, 2045	$ 200	Repay outstanding commercial paper obligations and general corporate purposes
ACE	First Mortgage Bonds	3.50%	December 1, 2025	$ 150	Repay outstanding commercial paper obligations and general corporate purposes

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During the year ended December 31, 2014, the following long term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes	2.50%	June 1, 2024	$ 1,150	Finance a portion of the pending merger with PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.25 - 3.35%	June 30, 2018	$ 70	Procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 300	General corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 675	General corporate purposes
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	$ 12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Nonrecourse Debt	3.06 - 3.14%	January 5, 2037	$ 126	Antelope Valley solar development
ComEd	First Mortgage Bonds, Series 115	2.15%	January 15, 2019	$ 300	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 116	4.70%	January 15, 2044	$ 350	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds, Series 117	3.10%	November 1, 2024	$ 250	Repay commercial paper obligations and general corporate purposes
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	$ 300	Refinance existing mortgage bonds and general corporate purposes
PHI [(a)]	Energy Efficiency Project Financing	4.68%	February 10, 2015	$ 6	Funding to install energy conservation measures for the Natick Project
Pepco	First Mortgage Bonds	3.60%	March 15, 2024	$ 400	Repay $175M of 4.65% Senior Notes, repay outstanding commercial paper obligations, and general corporate purposes

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Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Pepco	Energy Efficiency Project Financing	3.12%	February 20, 2015	$ 12	Funding to install energy conservation measures for the State Department project
DPL	First Mortgage Bonds	3.50%	November 15, 2023	$ 200	Repay outstanding commercial paper obligations and general corporate purposes
ACE	First Mortgage Bonds	3.375%	September 1, 2024	$ 150	Repay $7M of 7.63% medium term notes, repay commercial paper issued to repay $100M term loan, and general commercial purposes

(a) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES financing was included with Generation.

During the year ended December 31, 2016, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 8
Exelon Corporate	Senior Notes	4.95%	June 15, 2035	$ 1
Generation	AVSR DOE Nonrecourse Debt [a]	2.29% - 3.56%	January 5, 2037	$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 4
Generation	Continental Wind Nonrecourse Debt [a]	6.00%	February 28, 2033	$ 29
Generation	CEU Upstream Nonrecourse Debt [a]	1mL + 2.25%	January 14, 2019	$ 46
Generation	ExGen Texas Power Nonrecourse Debt [a]	5.00%	September 18, 2021	$ 7
Generation	Sacramento Solar Nonrecourse Debt [a]	1mL + 2.25%	December 31, 2030	$ 33
Generation	Clean Horizons Nonrecourse Debt [a]	1mL + 2.25%	September 7, 2030	$ 32
Generation	ExGen Renewables Nonrecourse Debt[a]	3mL + 4.25%	February 6, 2021	$ 24
Generation	PES PGOV Notes Payable	6.70 - 7.46%	2017 - 2018	$ 1
Generation	NUKEM	3.35%	June 30, 2018	$ 12
Generation	NUKEM	3.25%	July 1, 2018	$ 10
Generation	Renewable Power Generation Nonrecourse Debt [a]	4.11%	March 31, 2035	$ 9

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Company	Type	Interest Rate	Maturity	Amount
Generation	SolGen Nonrecourse Debt [(a)]	3.93%	September 30, 2036	$ 2
ComEd	First Mortgage Bonds, Series 104	5.95%	August 15, 2016	$ 415
ComEd	First Mortgage Bonds, Series 111	1.95%	August 1, 2016	$ 250
PECO	First and Refunding Mortgage Bonds	1.20%	October 15, 2016	$ 300
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 1
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	$ 38
BGE	Notes	5.90%	October 1, 2016	$ 300
BGE	Securitization Bonds	5.82%	April 1, 2017	$ 40
PHI	Senior Unsecured Notes	5.90%	December 12, 2016	$ 190
DPL	First Mortgage Bonds	5.22%	December 30, 2016	$ 100
ACE	Transition Bonds	5.05%	October 20, 2020	$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	$ 34
ACE	First Mortgage Bonds	7.68%	August 23, 2016	$ 2

(a) See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of nonrecourse debt.

During the year ended December 31, 2015, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	$ 800
Exelon Corporate	Senior Unsecured Notes	3.95%	June 15, 2025	$ 443
Exelon Corporate	Senior Unsecured Notes	4.95%	June 15, 2035	$ 167
Exelon Corporate	Senior Unsecured Notes	5.10%	June 15, 2045	$ 259
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 1
Generation	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Generation	CEU Upstream Nonrecourse Debt	LIBOR + 2.25%	January 14, 2019	$ 9
Generation	AVSR DOE Nonrecourse Debt	2.29% - 3.56%	January 5, 2037	$ 23
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 3
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 8, 2021	$ 5
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 24

Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	$	2

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Company	Type	Interest Rate	Maturity	Amount
Generation	Sacramento PV Energy Nonrecourse Debt	2.58%	December 31, 2030	$ 2
Generation	Energy Efficiency Project	3.55%	November 15, 2016	$ 19
ComEd	First Mortgage Bonds, Series 101	4.70%	April 15, 2015	$ 260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 75
PHI	Senior Unsecured Notes	2.70%	October 1, 2015	$ 250
PHI (a)	Energy Efficiency Project Financing	4.68%	February 10, 2015	$ 7
PHI (a)	Energy Efficiency Project Financing	8.87%	June 1, 2021	$ 5
PHI (a)	Energy Efficiency Project Financing	7.61%	August 1, 2015	$ 1
PHI (a)	PES-PGOV Notes Payable	6.70 - 7.46%	2017-2018	$ 1
Pepco	Energy Efficiency Project Financing	3.12%	February 20, 2015	$ 12
DPL	Senior Unsecured Notes	5.00%	June 1, 2015	$ 100
ACE	Secured Medium-Term Notes Series C	7.68%	August 24, 2015	$ 15
ACE	Transition Bonds	5.05%	October 20, 2020	$ 12
ACE	Transition Bonds	5.55%	October 20, 2023	$ 32

(a) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES financing was included with Generation.

During the year ended December 31, 2014, the following long term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Senior Unsecured Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Notes	4.10%	July 1, 2014	$ 20
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 3
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 18
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 2
Generation	AVSR DOE Nonrecourse Debt	2.33% - 3.55%	January 5, 2037	$ 15
Generation	Clean Horizons Solar Nonrecourse Debt	2.56%	September 7, 2030	$ 2
Generation	Sacramento Solar Nonrecourse Debt	2.56%	December 31, 2030	$ 2
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	$ 12
ComEd	First Mortgage Bonds, Series 110	1.63%	January 15, 2014	$ 600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	$ 17

PECO	First and Refunding Mortgage Bonds	5.00%	October 1, 2014	$ 250

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Company	Type	Interest Rate	Maturity	Amount
BGE	Rate Stabilization Bonds	5.72%	April 1, 2017	$ 35
BGE	Rate Stabilization Bonds	5.72%	October 1, 2014	$ 35
PHI [(a)]	PES-PGOV Notes Payable	6.70 - 7.46%	2017-2018	$ 1
Pepco	Senior Notes	4.65%	April 15, 2014	$ 175
DPL	Senior Unsecured Notes	5.00%	June 1, 2015	$ 100
ACE	Term Loan	LIBOR + 0.75%	November 10, 2014	$ 100
ACE	Variable Rate Demand Bonds	variable	April 15, 2014	$ 18
ACE	Transition Bonds	5.05%	October 20, 2020	$ 11
ACE	Transition Bonds	5.55%	October 20, 2023	$ 30
ACE	Secured Medium-Term Notes	7.63%	August 29, 2014	$ 7

(a) Represents Pepco Energy Services energy efficiency project financing. As of the date of the merger, PES debt was included with Generation.

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends

Cash dividend payments and distributions for the year ended December 31, 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [(a)]	$ 1,166	$ 1,105	$ 1,486
Generation [(a)]	922	2,474	1,066
ComEd	369	299	307
PECO	277	279	320
BGE [(b)]	187	171	13
Pepco	136	146	86
DPL	54	92	100
ACE	63	12	26

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
PHI	$ 273	$	$ 275	$ 272

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2016, 2015, and 2014 activity includes CENG on a fully consolidated basis beginning April 1, 2014.
(b) Includes dividends paid on BGE s preference stock.

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Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2016 and for the first quarter of 2017 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
First Quarter 2017	January 31, 2017	February 15, 2017	March 10, 2017	$ 0.3275

(a) Exelon s Board of Directors has approved a dividend policy providing a raise of 2.5% each year for three years, beginning with the June 2016 dividend.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Exelon [(a)]	$ (353)	$ 80	$ 122
Generation [(a)]	620		17
ComEd	(294)	(10)	120
BGE	(165)	90	(15)
Pepco	(41)	(40)	(47)
DPL	(105)	(1)	(41)
ACE	(5)	(122)	7

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	For the Year Ended December 31, 2015	For the Year Ended December 31, 2014
PHI	$ (515)	$ (121)	$ 34	$ 183

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, beginning on April 1, 2014, CENG s revenues net of purchased power and fuel expenses are included on a fully consolidated basis.

Retirement of Long-Term Debt to Financing Affiliates

There were no retirements of long-term debt to financing affiliates during 2016, 2015 and 2014 by the Registrants.

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Contributions from Parent/Member.

Contributions from Parent/Member (Exelon) during 2016, 2015 and 2014 by Registrant were as follows:

	2016	2015	2014
Generation	$ 142	$ 47	$ 53
ComEd [(a)(b)]	473	209	278
PECO [(b)]	18	16	24
BGE [(b)]	61	7	
Pepco [(c)]	187	112	80
DPL [(c)]	152	75	130
ACE [(c)]	139	95	

	Successor	*Predecessor*		
	March 24, 2016 to December 31, 2016	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
PHI [(b)]	$ 1,251	$	$	$

(a) Additional contributions from parent or external debt financing may be required as a result of increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansions and Exelon s agreement to indemnify ComEd for any unfavorable after-tax impacts associated with ComEd s LKE tax matter.
(b) Contribution paid by Exelon.
(c) 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. 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 6.990% 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 6.700% Cumulative Preference Stock, 1993 Series for $90 million, plus accrued and unpaid dividends. As of December 31, 2016, BGE no longer has any preferred stock outstanding. See Note 22 Earnings Per Share of the Combined Notes to Consolidated Financial Statements for further details.

Other

For the year ended December 31, 2016, other financing activities primarily consists of debt issuance costs. See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

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Credit Matters

Market Conditions

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 December 31, 2016, and of which no financial institution has more than 7% of the aggregate commitments for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE. The Registrants had access to the commercial paper market during 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 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 December 31, 2016, it would have been required to provide incremental collateral of $1.9 billion to meet collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within its current available credit facility capacities of $4.2 billion.

The following table presents 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 December 31, 2016 and available credit facility capacity prior to any incremental collateral at December 31, 2016:

	PJM Credit Policy Collateral	Other Incremental Collateral Required [a]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 19	$	$ 998
PECO	2	31	598
BGE	2	62	600
Pepco			300
DPL	3	10	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 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.

See Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure. At December 31, 2016, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	54%	36%	44%	42%	42%	41%	50%	50%	53%
Long-term debt to affiliates (a)	1%	4%	1%	3%	5%	%	%	%	%
Common equity	43%	%	55%	55%	52%		50%	50%	47%
Member s equity	%	57%	%	%	%	55%			
Preference Stock	%	%	%	%		%	%	%	%
Commercial paper and notes payable	2%	3%		%	1%	4%	%	%	%

(a) Includes approximately $641 million, $205 million, $184 million and $252 million owed to unconsolidated affiliates of Exelon, ComEd, PECO and BGE respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

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 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

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Intercompany Money Pool

To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, both Exelon and PHI operate an intercompany money pool. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of December 31, 2016, are presented in the following tables:

Exelon Intercompany Money Pool	**For the Year Ended December 31, 2016**		**As of December 31, 2016**
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
Exelon Corporate	$ 1,534	$	$ 88
Generation		1,292	(55)
PECO	395		131
BSC		387	(219)
PHI Corporate [(a)]		53	
PCI [(a)]	63		55

(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	**For the Year Ended December 31, 2016**		**As of December 31, 2016**
Contributed (borrowed)	**Maximum Contributed**	**Maximum Borrowed**	**Contributed (Borrowed)**
PHI Corporate	$ 152	$	$
Pepco			
DPL			
ACE			
PHISCO	26	152	

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 16 Asset Retirement Obligations 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.

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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 [(c)]	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	125
ACE	NJBPU	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 December 31, 2016 and has an expiration date of June 1, 2019 and March 1, 2019, respectively.

(c) In December 2016, BGE filed an application for $1 billion of long term financing authority with the MDPSC.

Exelon s ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account. In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE was prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid. Pepco, DPL and ACE are subject to certain dividend restrictions established by settlements approved in NJ, DE, MD and the DC. Pepco, DPL and ACE are prohibited from paying a dividend on their common shares if (a) after the dividend payment, Pepco s, DPL s or ACE s equity ratio would be below 48% as equity levels are calculated under the ratemaking precedents of the Commissions and the Board or (b) Pepco s, DPL s or ACE s senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. At December 31, 2016, Exelon had retained earnings of $12,030 million, including Generation s undistributed earnings of $2,275 million, ComEd s retained earnings of $987 million consisting of retained earnings appropriated for future dividends of $2,626 million partially offset by $1,639 million of unappropriated retained deficit, PECO s retained earnings of $941 million and BGE s retained earnings $1,427 million. At December 31, 2016, Pepco had retained earnings of $991 million, DPL had retained earnings of $562 million and

ACE had retained earnings of $122 million. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

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Contractual Obligations

The following tables summarize the Registrants future estimated cash payments as of December 31, 2016 under existing contractual obligations, including payments due by period. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within			
	Total	**2017**	**2018-2019**	**2020-2021**	**Due 2022 and beyond**
Long-term debt [(a)]	$ 33,959	$ 2,430	$ 2,751	$ 5,705	$ 23,073
Interest payments on long-term debt [(b)]	16,368	1,432	2,680	2,361	9,895
Liability and interest for uncertain tax positions [(c)]	150	150			
Capital leases	69	17	38	6	8
Operating leases [(d)]	1,726	183	302	273	968
Purchase power obligations [(e)]	1,502	508	626	148	220
Fuel purchase agreements [(f)]	7,693	1,297	2,165	1,501	2,730
Electric supply procurement [(f)]	3,632	2,261	1,357	14	
AEC purchase commitments [(f)]	6	1	3	2	
Curtailment services commitments [(f)]	148	61	80	7	
Long-term renewable energy and REC commitments [(g)]	1,517	107	213	225	972
Other purchase obligations [(h)]	7,739	5,426	1,292	517	504
Construction commitments [(i)]	317	276	41		
PJM regional transmission expansion commitments [(j)]	617	280	301	36	
SNF obligation [(k)]	1,024				1,024
Pension minimum funding requirement [(l)]	3,899	596	1,073	899	1,331
Total contractual obligations	$ 80,366	$ 15,025	$ 12,922	$ 11,694	$ 40,725

(a) Includes $648 million due after 2022 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016. Includes estimated interest payments due to ComEd, PECO, BGE, PHI, Pepco, DPL and ACE financing trusts.

(c) 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 in the second quarter of 2017. Exelon deposited with the IRS approximately $1.25 billion in October of 2016 and expects that the approximately $150 million remaining will be paid in the second quarter of 2017.

(d) Excludes Generation s contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO s meter reading operating lease.

(e) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation s expected payments under these arrangements at December 31, 2016, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services.

(g) Primarily related to ComEd 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 commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(h) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(i) Represents commitments for Generation s ongoing investments in new natural gas and biomass generation construction. Amount includes $139 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.
(j) Under their operating agreements with PJM, ComEd, PECO, BGE, Pepco, DPL and ACE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd, PECO, BGE, Pepco, DPL and ACE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.
(k) See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.
(l) These amounts represent Exelon s expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy for the legacy Exelon, CEG and CENG plans of contributing the greater of $250 million until the qualified plans are fully funded on an accumulated benefit obligation basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status thereafter. The remaining qualified pension plans contributions are generally based on the estimated minimum pension contributions required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2022 are not included. See Note 17 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 9,208	$ 1,117	$ 710	$ 2,800	$ 4,581
Interest payments on long-term debt [(a)]	5,086	383	752	574	3,377
Capital leases	22	5	11	6	
Operating leases [(b)]	914	70	105	95	644
Purchase power obligations [(c)]	1,502	508	626	148	220
Fuel purchase agreements [(d)]	6,510	1,057	1,825	1,296	2,332
Other purchase obligations [(e)]	1,828	1,111	296	115	306
Construction commitments [(f)]	317	276	41		
SNF obligation [(g)]	1,024				1,024
Total contractual obligations	$ 26,411	$ 4,527	$ 4,366	$ 5,034	$ 12,484

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016.

(b) Excludes Generation s contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations.

(c) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts presented represent Generation s expected payments under these arrangements at December 31, 2016, including those related to CENG. Expected payments include certain fixed capacity charges which may be reduced based on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature.

(d) Represents commitments to purchase fuel supplies for nuclear and fossil generation.

(e) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Represents commitments for Generation s ongoing investments in new natural gas and biomass generation construction. Amount includes $139 million of remaining commitments related to the construction of new combined-cycle gas turbine units in Texas. Achievement of commercial operations related to this project is expected in 2017.

(g) See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information regarding SNF obligations.

ComEd

	Payment due within				
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt [(a)]	$ 7,307	$ 425	$ 1,140	$ 850	$ 4,892
Interest payments on long-term debt [(b)]	4,400	283	473	421	3,223
Liability and interest for uncertain tax positions [(c)]	300	300			
Capital leases	8				8
Operating leases	29	11	12	6	
Electric supply procurement	733	461	272		
Long-term renewable energy and REC commitments [(d)]	1,375	80	156	167	972
Other purchase obligations [(e)]	830	692	102	32	4
PJM regional transmission expansion commitments [(f)]	97	64	33		
Total contractual obligations	$ 15,079	$ 2,316	$ 2,188	$ 1,476	$ 9,099

(a) Includes $206 million due after 2022 to a ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2016. Includes estimated interest payments due to the ComEd financing trust.

(c) 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 second quarter of 2017.

(d) Primarily related to ComEd 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 commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(e) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.

(f) Under its operating agreement with PJM, ComEd is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

PECO

	Payment due within
Total	2017

			2018-2019	2020-2021	Due 2022 and beyond
Long-term debt [a]	$ 2,784	$	$ 500	$ 300	$ 1,984
Interest payments on long-term debt [b]	1,679	120	190	185	1,184
Operating leases [c]	18	3	7	8	
Fuel purchase agreements [d]	327	99	144	37	47
Electric supply procurement [d]	481	397	84		
AEC purchase commitments [d]	8	2	4	2	
Other purchase obligations [e]	418	216	126	73	3
PJM regional transmission expansion commitments [f]	34	14	17	3	
Total contractual obligations	$ 5,749	$ 851	$ 1,072	$ 608	$ 3,218

(a) Includes $184 million due after 2022 to PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(c) Includes estimated cash payments for service fees related to PECO s meter reading operating lease.

(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs.
(e) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(f) Under its operating agreement with PJM, PECO is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PECO s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

BGE

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt [(a)]	$ 2,599	$ 41	$	$ 300	$ 2,258
Interest payments on long-term debt [(b)]	2,247	118	235	234	1,660
Operating leases	199	32	68	66	33
Fuel purchase agreements [(c)]	599	114	139	110	236
Electric supply procurement [(c)]	1,228	758	470		
Curtailment services commitments [(c)]	63	30	31	2	
Other purchase obligations [(d)]	851	633	132	85	1
PJM regional transmission expansion commitments [(e)]	226	113	99	14	
Total contractual obligations	$ 8,012	$ 1,839	$ 1,174	$ 811	$ 4,188

(a) Includes $258 million due after 2022 to the BGE financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.
(d) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(e) Under its operating agreement with PJM, BGE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent BGE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

PHI

Payment due within

	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 5,157	$ 251	$ 403	$ 255	$ 4,248
Interest payments on long-term debt [a]	1,329	244	461	424	200
Capital leases	39	12	27		
Operating leases	418	50	85	72	211
Fuel purchase agreements [b]	257	27	57	58	115
Long-term renewable energy and REC commitments [b]	143	28	57	58	
Electric supply procurement [b]	2,017	1,171	832	14	
Curtailment services commitments [b]	85	31	49	5	
Other purchase obligations [c]	3,017	2,394	441	84	98
PJM regional transmission expansion commitments [d]	260	89	152	19	
Total contractual obligations	$ 12,722	$ 4,297	$ 2,564	$ 989	$ 4,872

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, PHI is committed to the construction of transmission facilities to maintain system reliability. These amounts represent PHI s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Pepco

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 2,381	$ 16	$ 137	$ 2	$ 2,226
Interest payments on long-term debt (a)	695	121	237	228	109
Capital leases	39	12	27		
Operating leases	32	7	11	7	7
Electric supply procurement (b)	838	510	328		
Curtailment services commitments (b)	36	19	17		
Other purchase obligations (c)	1,345	1,165	164	8	8
PJM regional transmission expansion commitments (d)	104	6	79	19	
Total contractual obligations	$ 5,470	$ 1,856	$ 1,000	$ 264	$ 2,350

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase procure electric supply and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, Pepco is committed to the construction of transmission facilities to maintain system reliability. These amounts represent Pepco s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

DPL

	Total	Payment due within 2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 1,348	$ 119	$ 16	$	$ 1,213
Interest payments on long-term debt [(a)]	291	49	98	96	48
Operating leases	110	13	24	19	54
Fuel purchase agreements [(b)]	257	27	57	58	115
Long-term renewable energy and associated REC commitments [(b)]	143	28	57	58	
Electric supply procurement [(b)]	627	334	279	14	
Curtailment services commitments [(b)]	40	10	26	4	
Other purchase obligations [(c)]	897	568	175	69	85
PJM regional transmission expansion commitments [(d)]	63	47	16		
Total contractual obligations	$ 3,776	$ 1,195	$ 748	$ 318	$ 1,515

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(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric renewable energy and RECs, procure electric supply, and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, DPL is committed to the construction of transmission facilities to maintain system reliability. These amounts represent DPL s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

ACE

		Payment due within			
	Total	2017	2018-2019	2020-2021	Due 2022 and beyond
Long-term debt	$ 1,162	$ 35	$ 250	$ 253	$ 624
Interest payments on long-term debt [(a)]	259	60	98	72	29
Operating leases	54	8	15	11	20
Electric supply procurement [(b)]	552	327	225		
Curtailment services commitments [(b)]	9	2	6	1	
Other purchase obligations [(c)]	514	432	76	3	3
PJM regional transmission expansion commitments [(d)]	93	36	57		
Total contractual obligations	$ 2,643	$ 900	$ 727	$ 340	$ 676

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2016 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Represents commitments to procure electric supply and curtailment services.
(c) Represents the future estimated value at December 31, 2016 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the Registrants and third-parties for the provision of services and materials, entered into in the normal course of business not specifically reflected elsewhere in this table. These estimates are subject to significant variability from period to period.
(d) Under its operating agreement with PJM, ACE is committed to the construction of transmission facilities to maintain system reliability. These amounts represent ACE s expected portion of the costs to pay for the completion of the required construction projects. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants other commitments potentially triggered by future events.

For additional information regarding:

commercial paper, see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

long-term debt, see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

liabilities related to uncertain tax positions, see Note 15 Income Taxes of the Combined Notes to Consolidated Financial Statements.

capital lease obligations, see Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.

operating leases and rate relief commitments, see Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

- the nuclear decommissioning and SNF obligations, see Notes 16 Asset Retirement Obligations and 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

- regulatory commitments, see Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

- variable interest entities, see Note 2 Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.

- nuclear insurance, see Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

- new accounting pronouncements, see Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. 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.

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 2017 through 2019.

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 December 31, 2016, the proportion of expected generation hedged is 91%-94%, 56%-59% and 28%-31% for 2017, 2018 and 2019, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales to 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 December 31, 2016 market conditions and hedged position would be decreases in pre-tax net income of approximately $65 million, $410 million and $685 million, respectively, for 2017, 2018 and 2019. 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.

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 6,179 GWh, 7,310 GWh, and 10,571 GWh for the years ended December 31, 2016, 2015 and 2014 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 year ended December 31, 2016, resulted in pre-tax gains of $15 million due to net mark-to-market gains of $1 million and realized gains of $14 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, and one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $0.2 million of exposure during the year. 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 for the year ended December 31, 2016 of $8,921 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 39% of Generation s uranium concentrate requirements from 2017 through 2021 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon s and Generation s results of operations, cash flows and financial positions.

ComEd

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC s December 18, 2013 Order approved the reduction of ComEd s commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives. ComEd does not enter into derivatives for speculative or proprietary trading purposes.

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 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO has certain full requirements contracts, which are considered derivatives and qualify for the normal purchases and normal sales scope 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 13 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 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 13 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 13 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 13 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 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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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).

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 January 1, 2015 to December 31, 2016. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 13 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 December 31, 2016 and December 31, 2015.

	Exelon	Generation	ComEd	DPL	*Predecessor* PHI
Total mark-to-market energy contract net assets (liabilities) at January 1, 2015 [(a)]	$ 1,505	$ 1,712	$ (207)	$	$
Total change in fair value during 2015 of contracts recorded in result of operations	412	412			
Reclassification to realized at settlement of contracts recorded in results of operations	(168)	(168)			
Reclassification to realized at settlement from accumulated OCI	(2)	(2)			
Changes in fair value recorded through regulatory assets and liabilities [(b)]	(40)		(40)	2	2
Changes in allocated collateral	(172)	(172)		(2)	(2)
Changes in net option premium paid/(received)	(58)	(58)			
Option premium amortization	(21)	(21)			
Upfront payments and amortizations [(c)]	50	50			
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 [(a)]	$ 1,506	$ 1,753	$ (247)	$	$

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2015, ComEd recorded a regulatory liability of $247 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. ComEd recorded $55 million of decreases in fair value and an increase for realized losses due to settlements of $(15) million in purchased power expense associated with floating-to-fixed energy swap suppliers for the year ended December 31, 2015.

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

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	Exelon	Generation	ComEd	DPL	*Successor* March 24 to December 31, PHI	*Predecessor* January 1 to March 23, PHI
Total mark-to-market energy contract net assets (liabilities) at December 31, 2015 [a]	$ 1,506	$ 1,753	$ (247)	$	$	$
Total change in fair value during 2016 of contracts recorded in result of operations	236	236				
Reclassification to realized at settlement of contracts recorded in results of operations	(265)	(265)				
Contracts received at acquisition date [b]	(59)	(59)				
Changes in fair value recorded through regulatory assets and liabilities [c]	(8)		(11)	4	3	1
Changes in allocated collateral	(908)	(905)		(4)	(3)	(1)
Changes in net option premium paid/(received)	66	66				
Option premium amortization	11	11				
Upfront payments and amortizations [d]	140	140				
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016 [a]	$ 719	$ 977	$ (258)	$	$	$

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) Includes fair value from contracts received at acquisition of ConEdison Solutions of $(59) million.
(c) For ComEd and DPL, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2016 ComEd recorded a regulatory liability of $258 million, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. For the year ended December 31, 2016, ComEd also recorded $29 million of decreases in fair value and realized losses due to settlements of $18 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2016.
(d) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

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 12 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.

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Exelon

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [a][b]:							
Actively quoted prices (Level 1)	$ 205	$ 8	$ (38)	$ (14)	$ (1)	$	$ 160
Prices provided by external sources (Level 2)	273	49	2				324
Prices based on model or other valuation methods (Level 3) [c]	162	123	49	8	(21)	(86)	235
Total	$ 640	$ 180	$ 13	$ (6)	$ (22)	$ (86)	$ 719

(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 $329 million at December 31, 2016.
(c) Includes ComEd s net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [a][b]:							
Actively quoted prices (Level 1)	$ 205	$ 8	$ (38)	$ (14)	$ (1)	$	$ 160
Prices provided by external sources (Level 2)	273	49	2				324
Prices based on model or other valuation methods (Level 3)	181	142	69	28	(1)	74	493
Total	$ 659	$ 199	$ 33	$ 14	$ (2)	$ 74	$ 977

(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 $329 million at December 31, 2016.

ComEd

	Maturities Within						
	2017	2018	2019	2020	2021	2022 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3) [(a)]	$ (19)	$ (19)	$ (20)	$ (20)	$ (20)	$ (160)	$ (258)

(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

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collateral, is represented by the fair value of contracts at the reporting date. See Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation s credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2016. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company s credit risk by credit rating of the counterparties. The figures in the tables below exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE, and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $14 million, $33 million, $26 million, $44 million, $16 million and $9 million respectively. See Note 27 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 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	$ 995	$	$ 995	1	$ 328
Non-investment grade	118	16	102		
No external ratings					
Internally rated investment grade	352	1	351		
Internally rated non-investment grade	72	8	64		
Total	$ 1,537	$ 25	$ 1,512	1	$ 328

	Maturity of Credit Risk Exposure			
Rating as of December 31, 2016	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 782	$ 207	$ 6	$ 995
Non-investment grade	73	45		118
No external ratings				
Internally rated investment grade	292	39	21	352
Internally rated non-investment grade	53	19		72
Total	$ 1,200	$ 310	$ 27	$ 1,537

Net Credit Exposure by Type of Counterparty	**As of December 31, 2016**
Financial institutions	$ 116
Investor-owned utilities, marketers, power producers	689
Energy cooperatives and municipalities	636
Other	71
Total	$ 1,512

(a) As of December 31, 2016, credit collateral held from counterparties where Generation had credit exposure included $9 million of cash and $16 million of letters of credit.

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ComEd

Credit risk for ComEd is governed by credit and collection policies, which are aligned with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Public Utilities Act prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 31 of the following year. ComEd s ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2016. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd s recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

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. ComEd s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2016, ComEd s credit exposure to energy suppliers was approximately $1 million.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO s provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2016.

PECO s supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. As of December 31, 2016, PECO had no net credit exposure with suppliers.

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PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements. As of December 31, 2016, PECO s credit exposure under its natural gas supply and asset management agreements with investment grade suppliers was immaterial.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Public Utilities Article of the Annotated Code of Maryland and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2016.

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 December 31, 2016, BGE had no net credit exposure with 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 December 31, 2016, BGE had credit exposure of $8 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

Credit risk for Pepco is managed by credit and collection policies, which are consistent with state regulatory requirements. Pepco is currently obligated to provide service to all retail electric customers within its franchised territory. Pepco records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with MDPSC and DCPSC regulations, applicable weather regulatory provisions are in effect January through December, the utility will not terminate service to any residential customer when weather conditions prohibit termination. Additional MDPSC cold weather requirements are in effect after November 1 and before April 1. Pepco s provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in MDPSC and DCPSC regulations. Pepco did not have any customers representing over 10% of its revenues as of December 31, 2016.

Pepco s full requirement wholesale electric power agreements in Maryland and the District of Columbia, that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth, subject to an unsecured cap. The credit position is based on the initial market price, which is the forward price of energy on the day. A similar agreement in the District of Columbia requires a supplier to meet its credit requirements with a specified amount equal to fifteen percent (15%) of the total purchase amount. As of December 31, 2016, Pepco had no net credit exposure with suppliers.

DPL

Credit risk for DPL is managed by credit and collection policies, which are consistent with state regulatory requirements. DPL is currently obligated to provide service to all retail electric customers within its franchised territory. DPL records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with DPSC and MDPSC regulations, applicable weather regulatory provisions are in effect January through December, the utility will not terminate service to any residential customer when weather conditions prohibit termination. Additional cold weather regulatory requirements are in effect after November 1 and before April 1. DPL s provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in DPSC and MDPSC regulations. DPL did not have any customers representing over 10% of its revenues as of December 31, 2016.

DPL 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 to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day. As of December 31, 2016, DPL had no net credit exposure with suppliers.

DPL conducts margining under it natural gas supply contracts. As of December 31, 2016, DPL s credit exposure under its natural gas supply and asset management agreements was immaterial.

ACE

Credit risk for ACE is managed by credit and collection policies, which are consistent with state regulatory requirements. ACE is currently obligated to provide service to all retail electric customers within its franchised territory. ACE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with NJBPU regulations, applicable weather regulatory provisions are in effect January through December, the utility will not terminate service to any residential customer when weather conditions prohibit termination. Additional cold weather regulatory requirements are in effect after November 15 and through March 15. ACE s provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in NJBPU regulations. ACE did not have any customers representing over 10% of its revenues as of December 31, 2016.

ACE s supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier s creditworthiness requirements, require a supplier to partially meet its credit requirements with an independent credit requirement in an amount equal to $2.4 million per

tranche and allow a supplier to meet its additional credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day. As of December 31, 2016, ACE had no net credit exposure with 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 13 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 ITEM 7. Liquidity and Capital Resources Credit Matters Exelon Credit Facilities for additional information.

As of December 31, 2016, Generation had cash collateral of $347 million posted and cash collateral held of $24 million for external counterparties with derivative positions, of which $329 million and $2 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 December 31, 2016, $8 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. As of December 31, 2015, Generation had cash collateral posted of $1,267 million and cash collateral held of $21 million for external counterparties with derivative positions, of which $1,234 million and $9 million in net cash collateral deposits were offset against energy derivatives and interest rate and foreign exchange derivatives related to underlying energy contracts, respectively. As of December 31, 2015, $3 million of cash collateral posted was not offset against net derivative positions because it was not associated with energy-related derivatives or as the balance sheet date there were no positions to offset. See Note 24 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

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ComEd

As of December 31, 2016, ComEd held $3 million in collateral from suppliers in association with standard block energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for renewable energy contracts. See Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

PECO

As of December 31, 2016, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 13 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 December 31, 2016, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply contracts, but was holding $1 million in collateral under its natural gas procurement contracts. See Note 13 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 13 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 December 31, 2016, DPL was not required to post collateral under its natural gas procurement contracts. See Note 13 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 13 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.

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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.

Interest Rate and Foreign Exchange Risk (All Registrants)

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, 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 December 31, 2016, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $659 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 approximately a $7 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2016. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation s nuclear plants. As of December 31, 2016, Generation s decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation s NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $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 7. 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.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Generation

General

Generation s integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. These segments are discussed in further detail in ITEM 1. BUSINESS Exelon Generation Company, LLC of this Form 10-K.

Executive Overview

A discussion of items pertinent to Generation s executive overview is set forth under ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared To Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of Generation s results of operations for 2016 compared to 2015 and 2015 compared to 2014 is set forth under Results of Operations Generation in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Generation s business is capital intensive and requires considerable capital resources. Generation s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.8 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Generation s capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon s pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to Generation s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Generation s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of Generation s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in ITEM 1. BUSINESS ComEd of this Form 10-K.

Executive Overview

A discussion of items pertinent to ComEd s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of ComEd s results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under Results of Operations ComEd in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ComEd s business is capital intensive and requires considerable capital resources. ComEd s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ComEd s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2016, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ComEd s capital requirements, including construction, retirement of debt, and contributions to Exelon s pension plans. Additionally, ComEd operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Financing Activities

A discussion of items pertinent to ComEd s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ComEd s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of ComEd s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of 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 distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in ITEM 1. BUSINESS PECO of this Form 10-K.

Executive Overview

A discussion of items pertinent to PECO s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of PECO s results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under Results of Operations PECO in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PECO s business is capital intensive and requires considerable capital resources. PECO s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or participation in the intercompany money pool. PECO s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2016, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund PECO s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, PECO operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to PECO s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PECO s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of PECO s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BGE

General

BGE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution service in central Maryland, including the City of Baltimore. This segment is discussed in further detail in ITEM 1. BUSINESS BGE of this Form 10-K.

Executive Overview

A discussion of items pertinent to BGE s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of BGE s results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under Results of Operations BGE in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

BGE s business is capital intensive and requires considerable capital resources. BGE s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. BGE s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where BGE no longer has access to the capital markets at reasonable terms, BGE has access to a revolving credit facility. At December 31, 2016, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund BGE s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, BGE operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to BGE s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to BGE s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to BGE s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to BGE is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of BGE s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of BGE s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
BGE

BGE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PHI

General

PHI has three reportable segments Pepco, DPL, and ACE. Its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services, and to a lesser extent, the purchase and regulated retail sale and supply of natural gas in Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS PHI of this Form 10-K.

Executive Overview

A discussion of items pertinent to PHI s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Successor Period of March 24, 2016 to December 31, 2016, Predecessor Period of January 1, 2016 to March 23, 2016, and Predecessor Period Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of PHI s results of operations for March 24, 2016 to December 31, 2016 and January 1, 2016 to March 23, 2016 and 2015 compared to 2014 is set forth under Results of Operations PHI in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

PHI s business is capital intensive and requires considerable capital resources. PHI s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper, borrowings from the Exelon money pool or capital contributions from Exelon. PHI s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund PHI s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, PHI operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PHI s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Investing Activities

A discussion of items pertinent to PHI s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Financing Activities

A discussion of items pertinent to PHI s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to PHI is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of PHI s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of PHI s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PHI

PHI is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Pepco

General

Pepco operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in District of Columbia and major portions of Prince George s County and Montgomery County in Maryland. This segment is discussed in further detail in ITEM 1. BUSINESS Pepco of this Form 10-K.

Executive Overview

A discussion of items pertinent to Pepco s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of Pepco s results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under Results of Operations Pepco in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

Pepco s business is capital intensive and requires considerable capital resources. Pepco s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. Pepco s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2016, Pepco had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund Pepco s capital requirements, including construction, retirement of debt, and contributions to Exelon s pension plans. Additionally, Pepco operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to Pepco s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to Pepco s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to Pepco s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to Pepco is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of Pepco s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of Pepco s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Pepco

Pepco is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

DPL

General

DPL operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in portions of Maryland and Delaware, and the purchase and regulated retail sale and supply of natural gas in New Castle County, Delaware. This segment is discussed in further detail in ITEM 1. BUSINESS DPL of this Form 10-K.

Executive Overview

A discussion of items pertinent to DPL s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of DPL s results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under Results of Operations DPL in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

DPL s business is capital intensive and requires considerable capital resources. DPL s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt or commercial paper. DPL s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where DPL no longer has access to the capital markets at reasonable terms, DPL has access to a revolving credit facility. At December 31, 2016, DPL had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund DPL s capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon s pension plans. Additionally, DPL operates in a rate-regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to DPL s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to DPL s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to DPL s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to DPL is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of DPL s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of DPL s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
DPL

DPL is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ACE

General

ACE operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in portions of southern New Jersey. This segment is discussed in further detail in ITEM 1. BUSINESS ACE of this Form 10-K.

Executive Overview

A discussion of items pertinent to ACE s executive overview is set forth under EXELON CORPORATION Executive Overview of this Form 10-K.

Results of Operations

Year Ended December 31, 2016 Compared to Year Ended December 31, 2015 and Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

A discussion of ACE s results of operations for 2016 compared to 2015 and for 2015 compared to 2014 is set forth under Results of Operations ACE in EXELON CORPORATION Results of Operations of this Form 10-K.

Liquidity and Capital Resources

ACE s business is capital intensive and requires considerable capital resources. ACE s capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long-term debt, commercial paper or credit facility borrowings. ACE s access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2016, ACE had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION Liquidity and Capital Resources and Note 14 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for further discussion.

Capital resources are used primarily to fund ACE s capital requirements, including construction, retirement of debt, and contributions to Exelon s pension plans. Additionally, ACE operates in rate-regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ACE s cash flows from operating activities is set forth under Cash Flows from Operating Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

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Cash Flows from Investing Activities

A discussion of items pertinent to ACE s cash flows from investing activities is set forth under Cash Flows from Investing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Cash Flows from Financing Activities

A discussion of items pertinent to ACE s cash flows from financing activities is set forth under Cash Flows from Financing Activities in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Credit Matters

A discussion of credit matters pertinent to ACE is set forth under Credit Matters in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Contractual Obligations and Off-Balance Sheet Arrangements

A discussion of ACE s contractual obligations, commercial commitments and off-balance sheet arrangements is set forth under Contractual Obligations and Off-Balance Sheet Arrangements in EXELON CORPORATION Liquidity and Capital Resources of this Form 10-K.

Critical Accounting Policies and Estimates

See All Registrants Critical Accounting Policies and Estimates above for a discussion of ACE s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK
ACE

ACE is exposed to market risks associated with credit and interest rates. These risks are described above under Quantitative and Qualitative Disclosures about Market Risk Exelon.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management s Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon s management conducted an assessment of the effectiveness of Exelon s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon s management concluded that, as of December 31, 2016, Exelon s internal control over financial reporting was effective.

We excluded ConEdison Solutions from our assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. The total assets and total operating revenues related to ConEdison Solutions, a wholly-owned subsidiary, represent less than 1% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

The effectiveness of Exelon s internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management s Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Generation s management conducted an assessment of the effectiveness of Generation s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Generation s management concluded that, as of December 31, 2016, Generation s internal control over financial reporting was effective.

We excluded ConEdison Solutions from our assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. The total assets and total operating revenues related to ConEdison Solutions, a wholly-owned subsidiary, represent less than 1% and 2%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

The effectiveness of Generation s internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management s Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ComEd s management conducted an assessment of the effectiveness of ComEd s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ComEd s management concluded that, as of December 31, 2016, ComEd s internal control over financial reporting was effective.

The effectiveness of ComEd s internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management s Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PECO s management conducted an assessment of the effectiveness of PECO s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PECO s management concluded that, as of December 31, 2016, PECO s internal control over financial reporting was effective.

The effectiveness of PECO s internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management s Report on Internal Control Over Financial Reporting

The management of Baltimore Gas and Electric Company (BGE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

BGE s management conducted an assessment of the effectiveness of BGE s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, BGE s management concluded that, as of December 31, 2016, BGE s internal control over financial reporting was effective.

The effectiveness of BGE s internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management s Report on Internal Control Over Financial Reporting

The management of Pepco Holdings LLC (PHI) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PHI s management conducted an assessment of the effectiveness of PHI s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, PHI s management concluded that, as of December 31, 2016, PHI s internal control over financial reporting was effective.

The effectiveness of PHI s internal control over financial reporting as of December 31, 2016, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

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Management s Report on Internal Control Over Financial Reporting

The management of Potomac Electric Power Company (Pepco) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Pepco s management conducted an assessment of the effectiveness of Pepco s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Pepco s management concluded that, as of December 31, 2016, Pepco s internal control over financial reporting was effective.

February 13, 2017

Management s Report on Internal Control Over Financial Reporting

The management of Delmarva Power & Light Company (DPL) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

DPL s management conducted an assessment of the effectiveness of DPL s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, DPL s management concluded that, as of December 31, 2016, DPL s internal control over financial reporting was effective.

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Management s Report on Internal Control Over Financial Reporting

The management of Atlantic City Electric Company (ACE) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ACE s management conducted an assessment of the effectiveness of ACE s internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, ACE s management concluded that, as of December 31, 2016, ACE s internal control over financial reporting was effective.

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management s Report on Internal Control Over Financial Reporting, management has excluded Consolidated Edison Solutions, Inc. from its assessment of internal control over financial reporting as of December 31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. We have also excluded Consolidated Edison Solutions, Inc. from our audit of internal control over financial reporting. Consolidated Edison Solutions, Inc. is a wholly-owned subsidiary whose total assets and total operating revenues represent less than 1% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

/s/ PricewaterhouseCoopers LLP

Chicago, Illinois

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC (the Company) and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in *Internal Control Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As described in Management s Report on Internal Control Over Financial Reporting, management has excluded Consolidated Edison Solutions, Inc. from its assessment of internal control over financial reporting as of December

31, 2016 because it was acquired by the Company in a purchase business combination on September 1, 2016. We have also excluded Consolidated Edison Solutions, Inc. from our audit of internal control over financial reporting. Consolidated Edison Solutions, Inc. is a wholly-owned subsidiary whose total assets and total operating revenues represent less than 1% and 2%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2016.

/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland

February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Commonwealth Edison Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Chicago, Illinois

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of PECO Energy Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Philadelphia, Pennsylvania

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Baltimore Gas and Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Baltimore Gas and Electric Company and its subsidiaries at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 8. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Baltimore, Maryland

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Pepco Holdings LLC and its subsidiaries (Successor) at December 31, 2016, and the results of their operations and their cash flows for the period from March 24, 2016 to December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Washington, D.C.

February 13, 2017

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Pepco Holdings LLC and its subsidiaries (formerly Pepco Holdings, Inc.) (Predecessor) at December 31, 2015, and the results of their operations and their cash flows for the period January 1, 2016 to March 23, 2016 and for each of the two years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the financial statements, the Company changed the manner in which it accounts for interest on uncertain tax positions in 2016.

/s/ PricewaterhouseCoopers LLP

Washington, D.C.

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Potomac Electric Power Company at December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Washington, D.C.

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company:

In our opinion, the financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Delmarva Power & Light Company at December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Washington, D.C.

February 13, 2017

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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Atlantic City Electric Company and its subsidiary at December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for its regulatory recovery mechanism for purchased power costs associated with Basic Generation Service in 2016.

/s/ PricewaterhouseCoopers LLP

Washington, D.C.

February 13, 2017

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Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	**For the Years Ended December 31, 2016**	**2015**	**2014**
Operating revenues			
Competitive businesses revenues	$ 16,324	$ 18,395	$ 16,637
Rate-regulated utility revenues	15,036	11,052	10,792
Total operating revenues	31,360	29,447	27,429
Operating expenses			
Competitive businesses purchased power and fuel	8,817	10,007	9,369
Rate-regulated utility purchased power and fuel	3,823	3,077	3,103
Purchased power and fuel from affiliates			531
Operating and maintenance	10,048	8,322	8,568
Depreciation and amortization	3,936	2,450	2,314
Taxes other than income	1,576	1,200	1,154
Total operating expenses	28,200	25,056	25,039
Equity in losses of unconsolidated affiliates			(20)
Gain (Loss) on sales of assets	(48)	18	437
Gain on consolidation and acquisition of businesses			289
Operating income	3,112	4,409	3,096
Other income and (deductions)			
Interest expense, net	(1,495)	(992)	(1,024)
Interest expense to affiliates	(41)	(41)	(41)
Other, net	413	(46)	455
Total other income and (deductions)	(1,123)	(1,079)	(610)
Income before income taxes	1,989	3,330	2,486
Income taxes	761	1,073	666
Equity in losses of unconsolidated affiliates	(24)	(7)	
Net income	1,204	2,250	1,820
Net income (loss) attributable to noncontrolling interests and preference stock dividends	70	(19)	197
Net income attributable to common shareholders	$ 1,134	$ 2,269	$ 1,623

Comprehensive income, net of income taxes

Net income	$ 1,204	$ 2,250	$ 1,820
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(48)	(46)	(30)
Actuarial loss reclassified to periodic benefit cost	184	220	147
Pension and non-pension postretirement benefit plan valuation adjustment	(181)	(99)	(497)
Unrealized gain (loss) on cash flow hedges	2	9	(148)
Unrealized gain on marketable securities	1		1
Unrealized (loss) gain on equity investments	(4)	(3)	8
Unrealized gain (loss) on foreign currency translation	10	(21)	(9)
Reversal of CENG equity method AOCI			(116)
Other comprehensive (loss) income	(36)	60	(644)
Comprehensive income	1,168	2,310	1,176
Comprehensive income (loss) attributable to noncontrolling interests and preference stock dividends	70	(19)	197
Comprehensive income attributable to common shareholders	$ 1,098	$ 2,329	$ 979
Average shares of common stock outstanding:			
Basic	924	890	860
Diluted	927	893	864
Earnings per average common share:			
Basic	$ 1.23	$ 2.55	$ 1.89
Diluted	$ 1.22	$ 2.54	$ 1.88
Dividends per common share	$ 1.26	$ 1.24	$ 1.24

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 1,204	$ 2,250	$ 1,820
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion, including nuclear fuel and energy contract amortization	5,576	3,987	3,868
Impairments of long-lived assets	306	36	687
Gain on consolidation and acquisition of businesses			(296)
(Gain) Loss on sales of assets	48	(18)	(437)
Deferred income taxes and amortization of investment tax credits	664	752	502
Net fair value changes related to derivatives	24	(367)	716
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(229)	131	(210)
Other non-cash operating activities	1,333	1,109	1,054
Changes in assets and liabilities:			
Accounts receivable	(432)	240	(318)
Inventories	7	4	(380)
Accounts payable and accrued expenses	771	(121)	49
Option premiums (paid) received, net	(66)	58	38
Collateral received (posted), net	931	347	(1,719)
Income taxes	576	97	(143)
Pension and non-pension postretirement benefit contributions	(397)	(502)	(617)
Deposit with IRS	(1,250)		
Other assets and liabilities	(621)	(387)	(157)
Net cash flows provided by operating activities	8,445	7,616	4,457
Cash flows from investing activities			
Capital expenditures	(8,553)	(7,624)	(6,077)
Proceeds from termination of direct financing lease investment	360		335
Proceeds from nuclear decommissioning trust fund sales	9,496	6,895	7,396
Investment in nuclear decommissioning trust funds	(9,738)	(7,147)	(7,551)
Cash and restricted cash acquired from consolidations and acquisitions			140
Acquisitions of businesses, net	(6,934)	(40)	(386)
Proceeds from sales of long-lived assets	61	147	1,719
Proceeds from sales of investments			7
Purchases of investments			(3)
Change in restricted cash	(42)	66	(104)
Distribution from CENG			13

Other investing activities	(153)	(119)	(88)
Net cash flows used in investing activities	(15,503)	(7,822)	(4,599)
Cash flows from financing activities			
Changes in short-term borrowings	(353)	80	122
Proceeds from short-term borrowings with maturities greater than 90 days	240		
Repayments on short-term borrowings with maturities greater than 90 days	(462)		
Issuance of long-term debt	4,716	6,709	3,463
Retirement of long-term debt	(1,936)	(2,687)	(1,545)
Issuance of common stock		1,868	
Redemption of preference stock	(190)		
Distributions to noncontrolling interests of consolidated VIE			(421)
Dividends paid on common stock	(1,166)	(1,105)	(1,065)
Proceeds from employee stock plans	55	32	35
Sale of noncontrolling interests	372	32	
Other financing activities	(85)	(99)	(178)
Net cash flows provided by financing activities	1,191	4,830	411
(Decrease) Increase in cash and cash equivalents	(5,867)	4,624	269
Cash and cash equivalents at beginning of period	6,502	1,878	1,609
Cash and cash equivalents at end of period	$ 635	$ 6,502	$ 1,878

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 635	$ 6,502
Restricted cash and cash equivalents	253	205
Deposit with IRS	1,250	
Accounts receivable, net		
Customer	4,158	3,187
Other	1,201	912
Mark-to-market derivative assets	917	1,365
Unamortized energy contract assets	88	86
Inventories, net		
Fossil fuel	364	462
Materials and supplies	1,274	1,104
Regulatory assets	1,342	759
Other	930	752
Total current assets	12,412	15,334
Property, plant and equipment, net	71,555	57,439
Deferred debits and other assets		
Regulatory assets	10,046	6,065
Nuclear decommissioning trust funds	11,061	10,342
Investments	629	639
Goodwill	6,677	2,672
Mark-to-market derivative assets	492	758
Unamortized energy contract assets	447	484
Pledged assets for Zion Station decommissioning	113	206
Other	1,472	1,445
Total deferred debits and other assets	30,937	22,611
Total assets [(a)]	$ 114,904	$ 95,384

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 1,267	$ 533
Long-term debt due within one year	2,430	1,500
Accounts payable	3,441	2,883
Accrued expenses	3,460	2,376
Payables to affiliates	8	8
Regulatory liabilities	602	369
Mark-to-market derivative liabilities	282	205
Unamortized energy contract liabilities	407	100
Renewable energy credit obligation	428	302
PHI Merger related obligation	151	
Other	981	842
Total current liabilities	13,457	9,118
Long-term debt	31,575	23,645
Long-term debt to financing trusts	641	641
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	18,138	13,776
Asset retirement obligations	9,111	8,585
Pension obligations	4,248	3,385
Non-pension postretirement benefit obligations	1,848	1,618
Spent nuclear fuel obligation	1,024	1,021
Regulatory liabilities	4,187	4,201
Mark-to-market derivative liabilities	392	374
Unamortized energy contract liabilities	830	117
Payable for Zion Station decommissioning	14	90
Other	1,827	1,491
Total deferred credits and other liabilities	41,619	34,658
Total liabilities [(a)]	87,292	68,062
Commitments and contingencies		
Contingently redeemable noncontrolling interests		28
Shareholders equity		
Common stock (No par value, 2000 shares authorized, 924 shares and 920 shares outstanding at December 31, 2016 and 2015, respectively)	18,794	18,676
Treasury stock, at cost (35 shares at December 31, 2016 and 2015, respectively)	(2,327)	(2,327)

Retained earnings	12,030	12,068
Accumulated other comprehensive loss, net	(2,660)	(2,624)
Total shareholders equity	25,837	25,793
BGE preference stock not subject to mandatory redemption		193
Noncontrolling interests	1,775	1,308
Total equity	27,612	27,294
Total liabilities and shareholders equity	$ 114,904	$ 95,384

(a) Exelon s consolidated assets include $8,893 million and $8,268 million at December 31, 2016 and December 31, 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $3,356 million and $3,264 million at December 31, 2016 and December 31, 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Preference Stock	Total Shareholders Equity
Balance, December 31, 2013	892,034	$ 16,741	$ (2,327)	$ 10,358	$ (2,040)	$ 15	$ 193	$ 22,940
Net income				1,623		184	13	1,820
Long-term incentive plan activity	1,574	72						72
Employee stock purchase plan issuances	960	35						35
Tax benefit on stock compensation		(8)						(8)
Acquisition of noncontrolling interests		(2)				6		4
Common stock dividends				(1,071)				(1,071)
Preference stock dividends							(13)	(13)
Fair value of financing contract payments		(131)						(131)
Noncontrolling interests established upon consolidation of CENG						1,548		1,548
Transfer of CENG pension and non-pension postretirement benefit obligations		2						2
Consolidated VIE dividend to noncontrolling interests						(421)		(421)
Reversal of CENG equity method AOCI, net of income taxes					(116)			(116)
Other comprehensive loss, net of income taxes					(528)			(528)
Balance, December 31, 2014	894,568	$ 16,709	$ (2,327)	$ 10,910	$ (2,684)	$ 1,332	$ 193	$ 24,133
Net income (loss)				2,269		(32)	13	2,250
Long-term incentive plan activity	1,430	70						70
	1,170	32						32

Employee stock purchase plan issuances								
Issuance of common stock	57,500	1,868						1,868
Tax benefit on stock compensation		(3)						(3)
Acquisition of noncontrolling interests						4		4
Adjustment of contingently redeemable noncontrolling interests due to release of contingency						4		4
Common stock dividends				(1,111)				(1,111)
Preference stock dividends							(13)	(13)
Other comprehensive income, net of income taxes					60			60
Balance, December 31, 2015	954,668	$ 18,676	$ (2,327)	$ 12,068	$ (2,624)	$ 1,308	$ 193	$ 27,294
Net income				1,134		62	8	1,204
Long-term incentive plan activity	2,868	85						85
Employee stock purchase plan issuances	1,242	55						55
Tax benefit on stock compensation		(18)						(18)
Changes in equity of noncontrolling interests						5		5
Sale of noncontrolling interests		(4)				400		396
Common stock dividends				(1,172)				(1,172)
Redemption of preference stock							(193)	(193)
Preference stock dividends							(8)	(8)
Other comprehensive loss, net of income taxes					(36)			(36)
Balance, December 31, 2016	958,778	$ 18,794	$ (2,327)	$ 12,030	$ (2,660)	$ 1,775	$	$ 27,612

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Operating revenues	$ 16,312	$ 18,386	$ 16,614
Operating revenues from affiliates	1,439	749	779
Total operating revenues	17,751	19,135	17,393
Operating expenses			
Purchased power and fuel	8,818	10,007	9,368
Purchased power and fuel from affiliates	12	14	557
Operating and maintenance	4,978	4,688	4,943
Operating and maintenance from affiliates	663	620	623
Depreciation and amortization	1,879	1,054	967
Taxes other than income	506	489	465
Total operating expenses	16,856	16,872	16,923
Equity in losses of unconsolidated affiliates			(20)
Gain (Loss) on sales of assets	(59)	12	437
Gain on consolidation and acquisition of businesses			289
Operating income	836	2,275	1,176
Other income and (deductions)			
Interest expense, net	(325)	(322)	(303)
Interest expense to affiliates	(39)	(43)	(53)
Other, net	401	(60)	406
Total other income and (deductions)	37	(425)	50
Income before income taxes	873	1,850	1,226
Income taxes	290	502	207
Equity in losses of unconsolidated affiliates	(25)	(8)	
Net income	558	1,340	1,019
Net income (loss) attributable to noncontrolling interests	62	(32)	184
Net income attributable to membership interest	$ 496	$ 1,372	$ 835

Comprehensive income, net of income taxes

Net income	$ 558	$ 1,340	$ 1,019
Other comprehensive income (loss), net of income taxes			
Unrealized gain (loss) on cash flow hedges	2	(3)	(132)
Unrealized (loss) gain on equity investments	(4)	(3)	8
Unrealized gain (loss) on foreign currency translation	10	(21)	(9)
Unrealized loss on marketable securities	1		(1)
Reversal of CENG equity method AOCI			(116)
Other comprehensive income (loss)	9	(27)	(250)
Comprehensive income	$ 567	$ 1,313	$ 769
Comprehensive income (loss) attributable to noncontrolling interests	62	(32)	184
Comprehensive income attributable to membership interest	$ 505	$ 1,345	$ 585

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 558	$ 1,340	$ 1,019
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,519	2,589	2,519
Impairment of long-lived assets	243	12	663
Gain on consolidation and acquisition of businesses			(296)
(Gain) Loss on sales of assets	59	(12)	(437)
Deferred income taxes and amortization of investment tax credits	(269)	49	(198)
Net fair value changes related to derivatives	40	(249)	635
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(229)	131	(210)
Other non-cash operating activities	15	268	346
Changes in assets and liabilities:			
Accounts receivable	(152)	194	(215)
Receivables from and payables to affiliates, net	(21)	15	15
Inventories	(4)	16	(359)
Accounts payable and accrued expenses	29	(149)	29
Option premiums (paid) received, net	(66)	58	38
Collateral received (posted), net	923	407	(1,748)
Income taxes	182	(18)	265
Pension and non-pension postretirement benefit contributions	(152)	(245)	(297)
Other assets and liabilities	(231)	(207)	57
Net cash flows provided by operating activities	4,444	4,199	1,826
Cash flows from investing activities			
Capital expenditures	(3,078)	(3,841)	(3,012)
Proceeds from nuclear decommissioning trust fund sales	9,496	6,895	7,396
Investment in nuclear decommissioning trust funds	(9,738)	(7,147)	(7,551)
Cash and restricted cash acquired from consolidations and acquisitions			140
Proceeds from sales of long-lived assets	37	147	1,719
Acquisitions of businesses, net	(293)	(40)	(386)
Change in restricted cash	(35)	35	(87)
Changes in Exelon intercompany money pool			44
Distribution from CENG			13
Other investing activities	(240)	(118)	(43)

Net cash flows used in investing activities	(3,851)	(4,069)	(1,767)
Cash flows from financing activities			
Change in short-term borrowings	620		17
Proceeds from short-term borrowings with maturities greater than 90 days	240		
Repayments of short-term borrowings with maturities greater than 90 days	(162)		
Issuance of long-term debt	388	1,309	1,112
Retirement of long-term debt	(202)	(89)	(586)
Retirement of long-term debt to affiliate		(550)	
Changes in Exelon intercompany money pool	(1,191)	1,252	
Distribution to member	(922)	(2,474)	(645)
Distribution to noncontrolling interests of consolidated VIE			(421)
Contribution from member	142	47	53
Sale of noncontrolling interests	372	32	
Other financing activities	(19)	(6)	(67)
Net cash flows used in financing activities	(734)	(479)	(537)
Decrease in cash and cash equivalents	(141)	(349)	(478)
Cash and cash equivalents at beginning of period	431	780	1,258
Cash and cash equivalents at end of period	$ 290	$ 431	$ 780

See the Combined Notes to Consolidated Financial Statements

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Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 290	$ 431
Restricted cash and cash equivalents	158	123
Accounts receivable, net		
Customer	2,433	2,095
Other	558	360
Mark-to-market derivative assets	917	1,365
Receivables from affiliates	156	83
Unamortized energy contract assets	88	86
Inventories, net		
Fossil fuel	292	384
Materials and supplies	935	880
Other	701	535
Total current assets	6,528	6,342
Property, plant and equipment, net	25,585	25,843
Deferred debits and other assets		
Nuclear decommissioning trust funds	11,061	10,342
Investments	418	210
Goodwill	47	47
Mark-to-market derivative assets	476	733
Prepaid pension asset	1,595	1,689
Pledged assets for Zion Station decommissioning	113	206
Unamortized energy contract assets	447	484
Deferred income taxes	16	6
Other	688	627
Total deferred debits and other assets	14,861	14,344
Total assets [(a)]	$ 46,974	$ 46,529

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Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 699	$ 29
Long-term debt due within one year	1,117	90
Accounts payable	1,610	1,583
Accrued expenses	989	935
Payables to affiliates	137	104
Borrowings from Exelon intercompany money pool	55	1,252
Mark-to-market derivative liabilities	263	182
Unamortized energy contract liabilities	72	100
Renewable energy credit obligation	428	302
Other	313	356
Total current liabilities	5,683	4,933
Long-term debt	7,202	7,936
Long-term debt to affiliate	922	933
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,585	5,845
Asset retirement obligations	8,922	8,431
Non-pension postretirement benefit obligations	930	924
Spent nuclear fuel obligation	1,024	1,021
Payables to affiliates	2,608	2,577
Mark-to-market derivative liabilities	153	150
Unamortized energy contract liabilities	80	117
Payable for Zion Station decommissioning	14	90
Other	595	602
Total deferred credits and other liabilities	19,911	19,757
Total liabilities [(a)]	33,718	33,559
Commitments and contingencies		
Contingently redeemable noncontrolling interests		28
Equity		
Member s equity		
Membership interest	9,261	8,997
Undistributed earnings	2,275	2,701
Accumulated other comprehensive loss, net	(54)	(63)

Total member s equity	11,482	11,635
Noncontrolling interests	1,774	1,307
Total equity	13,256	12,942
Total liabilities and equity	$ 46,974	$ 46,529

(a) Generation s consolidated assets include $8,817 million and $8,235 million at December 31, 2016 and 2015, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation s consolidated liabilities include $3,170 million and $3,135 million at December 31, 2016 and 2015, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2 Variable Interest Entities.

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Exelon Generation Company, LLC and Subsidiary Companies

Consolidated Statements of Changes in Equity

	Member s Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total Equity
Balance, December 31, 2013	$ 8,898	$ 3,613	$ 214	$ 17	$ 12,742
Net income		835		184	1,019
Acquisition of noncontrolling interests				5	5
Allocation of tax benefit from member	53				53
Distribution to member		(645)			(645)
Noncontrolling interests established upon consolidation of CENG				1,548	1,548
Consolidated VIE dividend to noncontrolling interests				(421)	(421)
Reversal of CENG equity method AOCI, net of income taxes			(116)		(116)
Other comprehensive loss, net of income taxes			(134)		(134)
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$ 14,051
Net income (loss)		1,372		(32)	1,340
Acquisition of noncontrolling interests	(1)			2	1
Adjustment of contingently redeemable noncontrolling interests due to release of contingency				4	4
Allocation of tax benefit from member	47				47
Distribution to member		(2,474)			(2,474)
Other comprehensive loss, net of income taxes			(27)		(27)
Balance, December 31, 2015	$ 8,997	$ 2,701	$ (63)	$ 1,307	$ 12,942
Net income		496		62	558
Sale of noncontrolling interests	(4)			400	396
Changes in equity of noncontrolling interests				5	5
Allocation of tax benefit from member	98				98

Contribution from member	170								170
Distribution to member			(922)						(922)
Other comprehensive income, net of income taxes					9				9
Balance, December 31, 2016	$ 9,261	$	2,275	$	(54)	$	1,774		$ 13,256

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Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$ 5,239	$ 4,901	$ 4,560
Operating revenues from affiliates	15	4	4
Total operating revenues	5,254	4,905	4,564
Operating expenses			
Purchased power	1,411	1,301	1,001
Purchased power from affiliate	47	18	176
Operating and maintenance	1,303	1,372	1,263
Operating and maintenance from affiliate	227	195	166
Depreciation and amortization	775	707	687
Taxes other than income	293	296	293
Total operating expenses	4,056	3,889	3,586
Gain on sales of assets	7	1	2
Operating income	1,205	1,017	980
Other income and (deductions)			
Interest expense, net	(448)	(319)	(308)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	(65)	21	17
Total other income and (deductions)	(526)	(311)	(304)
Income before income taxes	679	706	676
Income taxes	301	280	268
Net income	$ 378	$ 426	$ 408
Comprehensive income	$ 378	$ 426	$ 408

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Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	**For the Years Ended December 31, 2016**	**2015**	**2014**
Cash flows from operating activities			
Net income	$ 378	$ 426	$ 408
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	775	707	687
Deferred income taxes and amortization of investment tax credits	439	353	433
Other non-cash operating activities	215	416	255
Changes in assets and liabilities:			
Accounts receivable	(25)	(93)	(121)
Receivables from and payables to affiliates, net	3	(19)	(11)
Inventories	1	(40)	(16)
Accounts payable and accrued expenses	339	68	95
Counterparty collateral received (posted), net and cash deposits	7	(33)	2
Income taxes	306	192	(159)
Pension and non-pension postretirement benefit contributions	(38)	(150)	(248)
Other assets and liabilities	105	69	1
Net cash flows provided by operating activities	2,505	1,896	1,326
Cash flows from investing activities			
Capital expenditures	(2,734)	(2,398)	(1,689)
Proceeds from sales of investments			7
Purchases of investments			(3)
Change in restricted cash		2	(2)
Other investing activities	49	34	32
Net cash flows used in investing activities	(2,685)	(2,362)	(1,655)
Cash flows from financing activities			
Changes in short-term borrowings	(294)	(10)	120
Issuance of long-term debt	1,200	850	900
Retirement of long-term debt	(665)	(260)	(617)
Contributions from parent	315	202	273
Dividends paid on common stock	(369)	(299)	(307)
Other financing activities	(18)	(16)	(10)
Net cash flows provided by financing activities	169	467	359
(Decrease) increase in cash and cash equivalents	(11)	1	30

Cash and cash equivalents at beginning of period		67		66		36
Cash and cash equivalents at end of period	$	56	$	67	$	66

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Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 56	$ 67
Restricted cash	2	2
Accounts receivable, net		
Customer	528	533
Other	218	272
Receivables from affiliates	356	199
Inventories, net	159	164
Regulatory assets	190	218
Other	45	63
Total current assets	1,554	1,518
Property, plant and equipment, net	19,335	17,502
Deferred debits and other assets		
Regulatory assets	977	895
Investments	6	6
Goodwill	2,625	2,625
Receivable from affiliates	2,170	2,172
Prepaid pension asset	1,343	1,490
Other	325	324
Total deferred debits and other assets	7,446	7,512
Total assets	$ 28,335	$ 26,532

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Commonwealth Edison Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$	$ 294
Long-term debt due within one year	425	665
Accounts payable	645	660
Accrued expenses	1,250	706
Payables to affiliates	65	62
Customer deposits	121	131
Regulatory liabilities	329	155
Mark-to-market derivative liability	19	23
Other	84	70
Total current liabilities	2,938	2,766
Long-term debt	6,608	5,844
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,364	4,914
Asset retirement obligations	119	111
Non-pension postretirement benefits obligations	239	259
Regulatory liabilities	3,369	3,459
Mark-to-market derivative liability	239	224
Other	529	507
Total deferred credits and other liabilities	9,859	9,474
Total liabilities	19,610	18,289
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	6,150	5,677
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,626	2,617
Total shareholders equity	8,725	8,243
Total liabilities and shareholders equity	$ 28,335	$ 26,532

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Commonwealth Edison Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders Equity

(In millions)	Common Stock	Other Paid-In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders Equity
Balance, December 31, 2013	$ 1,588	$ 5,190	$ (1,639)	$ 2,389	$ 7,528
Net income			408		408
Common stock dividends				(307)	(307)
Contribution from parent		273			273
Parent tax matter indemnification		5			5
Appropriation of retained earnings for future dividends			(408)	408	
Balance, Balance at December 31, 2014	$ 1,588	$ 5,468	$ (1,639)	$ 2,490	$ 7,907
Net income			426		426
Common stock dividends				(299)	(299)
Contribution from parent		202			202
Parent tax matter indemnification		7			7
Appropriation of retained earnings for future dividends			(426)	426	
Balance, December 31, 2015	$ 1,588	$ 5,677	$ (1,639)	$ 2,617	$ 8,243
Net income			378		378
Common stock dividends				(369)	(369)
Contribution from parent		315			315
Parent tax matter indemnification		158			158
Appropriation of retained earnings for future dividends			(378)	378	
Balance, December 31, 2016	$ 1,588	$ 6,150	$ (1,639)	$ 2,626	$ 8,725

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PECO Energy Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$ 2,524	$ 2,485	$ 2,446
Natural gas operating revenues	462	545	646
Operating revenues from affiliates	8	2	2
Total operating revenues	2,994	3,032	3,094
Operating expenses			
Purchased power	598	735	740
Purchased fuel	162	235	327
Purchased power from affiliate	287	220	194
Operating and maintenance	665	684	767
Operating and maintenance from affiliates	146	110	99
Depreciation and amortization	270	260	236
Taxes other than income	164	160	159
Total operating expenses	2,292	2,404	2,522
Gain on sales of assets		2	
Operating income	702	630	572
Other income and (deductions)			
Interest expense, net	(111)	(102)	(101)
Interest expense to affiliates	(12)	(12)	(12)
Other, net	8	5	7
Total other income and (deductions)	(115)	(109)	(106)
Income before income taxes	587	521	466
Income taxes	149	143	114
Net income	438	378	352
Net income attributable to common shareholder	$ 438	$ 378	$ 352
Comprehensive income	$ 438	$ 378	$ 352

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PECO Energy Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 438	$ 378	$ 352
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	270	260	236
Deferred income taxes and amortization of investment tax credits	78	90	88
Other non-cash operating activities	65	70	92
Changes in assets and liabilities:			
Accounts receivable	(71)	37	(16)
Receivables from and payables to affiliates, net	6	3	(6)
Inventories	6	10	2
Accounts payable and accrued expenses	67	(25)	58
Income taxes	8	(9)	(57)
Pension and non-pension postretirement benefit contributions	(30)	(40)	(16)
Other assets and liabilities	(8)	(4)	(21)
Net cash flows provided by operating activities	829	770	712
Cash flows from investing activities			
Capital expenditures	(686)	(601)	(661)
Changes in intercompany money pool	(131)		
Change in restricted cash	(1)	(1)	
Other investing activities	20	14	12
Net cash flows used in investing activities	(798)	(588)	(649)
Cash flows from financing activities			
Issuance of long-term debt	300	350	300
Retirement of long-term debt	(300)		(250)
Contributions from parent	18	16	24
Dividends paid on common stock	(277)	(279)	(320)
Other financing activities	(4)	(4)	(4)
Net cash flows provided by (used in) financing activities	(263)	83	(250)
(Decrease) Increase in cash and cash equivalents	(232)	265	(187)
Cash and cash equivalents at beginning of period	295	30	217
Cash and cash equivalents at end of period	$ 63	$ 295	$ 30

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PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 63	$ 295
Restricted cash and cash equivalents	4	3
Accounts receivable, net		
Customer	306	258
Other	131	146
Receivables from affiliates	4	2
Receivable from Exelon intercompany pool	131	
Inventories, net		
Fossil fuel	35	43
Materials and supplies	27	26
Prepaid utility taxes	9	11
Regulatory assets	29	34
Other	18	24
Total current assets	757	842
Property, plant and equipment, net	7,565	7,141
Deferred debits and other assets		
Regulatory assets	1,681	1,583
Investments	25	28
Receivable from affiliates	438	405
Prepaid pension asset	345	347
Other	20	21
Total deferred debits and other assets	2,509	2,384
Total assets	$ 10,831	$ 10,367

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PECO Energy Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Long-term debt due within one year	$	$ 300
Accounts payable	342	281
Accrued expenses	104	109
Payables to affiliates	63	55
Customer deposits	61	58
Regulatory liabilities	127	112
Other	30	29
Total current liabilities	727	944
Long-term debt	2,580	2,280
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,006	2,792
Asset retirement obligations	28	27
Non-pension postretirement benefits obligations	289	287
Regulatory liabilities	517	527
Other	85	90
Total deferred credits and other liabilities	3,925	3,723
Total liabilities	7,416	7,131
Commitments and contingencies		
Shareholder s equity		
Common stock	2,473	2,455
Retained earnings	941	780
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,415	3,236
Total liabilities and shareholder s equity	$ 10,831	$ 10,367

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PECO Energy Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholder s Equity

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholder s Equity
Balance, December 31, 2013	$ 2,415	$ 649	$ 1	$ 3,065
Net income		352		352
Common stock dividends		(320)		(320)
Allocation of tax benefit from parent	24			24
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income		378		378
Common stock dividends		(279)		(279)
Allocation of tax benefit from parent	16			16
Balance, December 31, 2015	$ 2,455	$ 780	$ 1	$ 3,236
Net income		438		438
Common stock dividends		(277)		(277)
Allocation of tax benefit from parent	18			18
Balance, December 31, 2016	$ 2,473	$ 941	$ 1	$ 3,415

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Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	**2016**	**2015**	**2014**
Operating revenues			
Electric operating revenues	$ 2,603	$ 2,490	$ 2,460
Natural gas operating revenues	609	631	680
Operating revenues from affiliates	21	14	25
Total operating revenues	3,233	3,135	3,165
Operating expenses			
Purchased power	528	602	733
Purchased fuel	162	205	302
Purchased power from affiliate	604	498	382
Operating and maintenance	605	565	614
Operating and maintenance from affiliates	132	118	103
Depreciation and amortization	423	366	371
Taxes other than income	229	224	221
Total operating expenses	2,683	2,578	2,726
Gain on sales of assets		1	
Operating income	550	558	439
Other income and (deductions)			
Interest expense, net	(87)	(83)	(90)
Interest expense to affiliates	(16)	(16)	(16)
Other, net	21	18	18
Total other income and (deductions)	(82)	(81)	(88)
Income before income taxes	468	477	351
Income taxes	174	189	140
Net income	294	288	211
Preference stock dividends	8	13	13
Net income attributable to common shareholder	$ 286	$ 275	$ 198
Comprehensive income	$ 294	$ 288	$ 211
Comprehensive income attributable to preference stock dividends	8	13	13

Comprehensive income attributable to common shareholder	$ 286	$ 275	$ 198

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 294	$ 288	$ 211
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	423	366	371
Impairment of long-lived assets and losses on regulatory assets	52		
Deferred income taxes and amortization of investment tax credits	118	165	116
Other non-cash operating activities	88	137	180
Changes in assets and liabilities:			
Accounts receivable	(98)	84	46
Receivables from and payables to affiliates, net	3	(2)	(1)
Inventories	1	18	(6)
Accounts payable and accrued expenses	138	(3)	(75)
Collateral received (posted), net		(27)	27
Income taxes	18	(54)	45
Pension and non-pension postretirement benefit contributions	(49)	(17)	(16)
Other assets and liabilities	(43)	(173)	(158)
Net cash flows provided by operating activities	945	782	740
Cash flows from investing activities			
Capital expenditures	(934)	(719)	(620)
Change in restricted cash		26	(22)
Other investing activities	24	18	20
Net cash flows used in investing activities	(910)	(675)	(622)
Cash flows from financing activities			
Changes in short-term borrowings	(165)	90	(15)
Issuance of long-term debt	850		
Retirement of long-term debt	(379)	(75)	(70)
Redemption of preference stock	(190)		
Dividends paid on common stock	(179)	(158)	
Dividends paid on preference stock	(8)	(13)	(13)
Contributions from parent	61	7	
Other financing activities	(11)	(13)	13
Net cash flows used in financing activities	(21)	(162)	(85)

Increase (Decrease) in cash and cash equivalents	14	(55)	33
Cash and cash equivalents at beginning of period	9	64	31
Cash and cash equivalents at end of period	$ 23	$ 9	$ 64

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Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 23	$ 9
Restricted cash and cash equivalents	24	24
Accounts receivable, net		
Customer	395	300
Other	102	112
Inventories, net		
Gas held in storage	30	36
Materials and supplies	38	33
Prepaid utility taxes	15	61
Regulatory assets	208	267
Other	7	3
Total current assets	842	845
Property, plant and equipment, net	7,040	6,597
Deferred debits and other assets		
Regulatory assets	504	514
Investments	12	12
Prepaid pension asset	297	319
Other	9	8
Total deferred debits and other assets	822	853
Total assets [(a)]	$ 8,704	$ 8,295

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Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 45	$ 210
Long-term debt due within one year	41	378
Accounts payable	205	209
Accrued expenses	175	110
Payables to affiliates	55	52
Customer deposits	110	102
Regulatory liabilities	50	38
Other	26	35
Total current liabilities	707	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	2,219	2,081
Asset retirement obligations	21	17
Non-pension postretirement benefits obligations	205	209
Regulatory liabilities	110	184
Other	61	61
Total deferred credits and other liabilities	2,616	2,552
Total liabilities [(a)]	5,856	5,418
Commitments and contingencies		
Shareholders equity		
Common stock	1,421	1,367
Retained earnings	1,427	1,320
Total shareholders equity	2,848	2,687
Preference stock not subject to mandatory redemption		190
Total equity	2,848	2,877
Total liabilities and shareholders equity	$ 8,704	$ 8,295

(a) BGE s consolidated assets include $26 million and $26 million at December 31, 2016 and December 31, 2015, respectively, of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include $42 million and $122 million at December 31, 2016 and December 31, 2015, respectively, of BGE s consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 2 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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Baltimore Gas and Electric Company and Subsidiary Companies

Consolidated Statements of Changes in Shareholders Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2013	$ 1,360	$ 1,005	$ 2,365	$ 190	$ 2,555
Net income		211	211		211
Preference stock dividends		(13)	(13)		(13)
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$ 2,753
Net income		288	288		288
Preference stock dividends		(13)	(13)		(13)
Common stock dividends		(158)	(158)		(158)
Contribution from parent	7		7		7
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$ 2,877
Net income		294	294		294
Preference stock dividends		(8)	(8)		(8)
Common stock dividends		(179)	(179)		(179)
Distribution to parent	(7)		(7)		(7)
Contribution from parent	61		61		61
Redemption of preference stock				(190)	(190)
Balance, December 31, 2016	$ 1,421	$ 1,427	$ 2,848	$	$ 2,848

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Pepco Holdings LLC and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

	Successor	*Predecessor*		
(In millions)	**March 24 to December 31, 2016**	**January 1 to March 23, 2016**	**For the Years Ended December 31, 2015**	**2014**
Operating revenues				
Electric operating revenues	$ 3,506	$ 1,096	$ 4,770	$ 4,614
Natural gas operating revenues	92	57	165	194
Operating revenues from affiliates	45			
Total operating revenues	3,643	1,153	4,935	4,808
Operating expenses				
Purchased power	925	471	1,986	1,940
Purchased fuel	36	26	87	117
Purchased power and fuel from affiliates	486			
Operating and maintenance	1,144	294	1,156	1,183
Operating and maintenance from affiliates	89			
Depreciation, amortization and accretion	515	152	624	526
Taxes other than income	354	105	455	437
Total operating expenses	3,549	1,048	4,308	4,203
(Loss) gain on sales of assets	(1)		46	
Operating income	93	105	673	605
Other income and (deductions)				
Interest expense, net	(195)	(65)	(280)	(269)
Other, net	44	(4)	88	44
Total other income and (deductions)	(151)	(69)	(192)	(225)
(Loss) income before income taxes	(58)	36	481	380
Income taxes	3	17	163	138
Net (loss) income from continuing operations	(61)	19	318	242
Net income from discontinued operations			9	
Net (loss) income attributable to membership interest/common shareholders	$ (61)	$ 19	$ 327	$ 242

Comprehensive income (loss), net of income taxes								
Net (loss) income	$	(61)	$	19	$	327	$	242
Other comprehensive income (loss), net of income taxes								
Pension and non-pension postretirement benefit plans:								
Actuarial loss (gain) reclassified to periodic cost				1		9		(12)
Unrealized loss on cash flow hedges						1		
Other comprehensive income (loss)				1		10		(12)
Comprehensive (loss) income	$	(61)	$	20	$	337	$	230

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Pepco Holdings LLC and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	*Successor* March 24 to December 31, 2016	*Predecessor* January 1 to March 23, 2016	For the Years Ended December 31, 2015	2014
Cash flows from operating activities				
Net (loss) income	$ (61)	$ 19	$ 327	$ 242
Income from discontinued operations, net of income taxes			(9)	
Adjustments to reconcile net (loss) income to net cash from operating activities:				
Depreciation, amortization and accretion	515	152	624	526
Impairment of long-lived assets				81
Loss (Gain) on sales of assets	1		(46)	
Deferred income taxes and amortization of investment tax credits	295	19	134	303
Net fair value changes related to derivatives		18		
Other non-cash operating activities	514	46	167	127
Changes in assets and liabilities:				
Accounts receivable	(21)	(28)	(105)	(2)
Receivables from and payables to affiliates, net	42			
Inventories	3	(4)		8
Accounts payable and accrued expenses	19	42	(41)	(31)
Collateral received, net		1		1
Income taxes	(22)	12	8	(197)
Pension and non-pension postretirement benefit contributions	(86)	(4)	(21)	(18)
Other assets and liabilities	(311)	(9)	(99)	(186)
Net cash flows provided by operating activities	888	264	939	854
Cash flows from investing activities				
Capital expenditures	(1,008)	(273)	(1,230)	(1,223)
Proceeds from sales of land	24		54	
Changes in restricted cash	(37)	3	6	(12)
Purchases of investments		(68)		
Other investing activities	(9)	(5)	9	9
Net cash flows used in investing activities	(1,030)	(343)	(1,161)	(1,226)
Cash flows from financing activities				
Changes in short-term borrowings	(515)	(121)	34	183
Proceeds from short-term borrowings with maturities greater than 90 days		500	300	
	(300)			

Repayments of short-term borrowings with maturities greater than 90 days				
Issuance of long-term debt	179		558	766
Retirement of long-term debt	(338)	(11)	(430)	(462)
Issuance of preferred stock			54	126
Dividends paid on common stock			(275)	(272)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation		2	18	33
Distribution to member	(273)			
Contribution from member	1,251			
Change in Exelon intercompany money pool	(6)			
Other financing activities	(5)	2	(26)	(11)
Net cash flows (used in) provided by financing activities	(7)	372	233	363
(Decrease) Increase in cash and cash equivalents	(149)	293	11	(9)
Cash and cash equivalents at beginning of period	319	26	15	24
Cash and cash equivalents at end of period	$ 170	$ 319	$ 26	$ 15

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Pepco Holdings LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	*Successor* December 31, 2016	*Predecessor* December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 170	$ 26
Restricted cash and cash equivalents	43	14
Accounts receivable, net		
Customer	496	581
Other	283	319
Mark-to-market derivative asset		18
Inventories, net		
Gas held in storage	6	9
Materials and supplies	116	122
Regulatory assets	653	305
Other	71	80
Total current assets	1,838	1,474
Property, plant and equipment, net	11,598	10,864
Deferred debits and other assets		
Regulatory assets	2,851	2,277
Investments	133	80
Goodwill	4,005	1,406
Long-term note receivable	4	4
Prepaid pension asset	509	
Deferred income taxes	6	14
Other	81	69
Total deferred debits and other assets	7,589	3,850
Total assets [(a)]	$ 21,025	$ 16,188

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Pepco Holdings LLC and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	*Successor* December 31, 2016	*Predecessor* December 31, 2015
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 522	$ 958
Long-term debt due within one year	253	456
Accounts payable	458	404
Accrued expenses	272	266
Payables to affiliates	94	
Unamortized energy contract liabilities	335	
Customer deposits	123	107
Merger related obligation	101	
Regulatory liabilities	79	66
Other	47	70
Total current liabilities	2,284	2,327
Long-term debt	5,645	4,823
Deferred credits and other liabilities		
Regulatory liabilities	158	147
Deferred income taxes and unamortized investment tax credits	3,775	3,406
Asset retirement obligations	14	8
Pension obligations		466
Non-pension postretirement benefit obligations	134	215
Unamortized energy contract liabilities	750	
Other	249	200
Total deferred credits and other liabilities	5,080	4,442
Total liabilities[(a)]	13,009	11,592
Commitments and contingencies		
Preferred stock[(b)]		183
Member s equity/Shareholders equity		
Membership interest/Common stock[(c)]	8,077	3,832
Undistributed (losses)/Retained earnings	(61)	617
Accumulated other comprehensive loss, net		(36)
Total member s equity/shareholders equity	8,016	4,413
Total liabilities and member s equity/shareholders equity	$ 21,025	$ 16,188

(a) PHI s consolidated total assets include $49 million and $30 million at December 31, 2016 and 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 $143 million and $172 million at December 31, 2016 and 2015, respectively, of PHI s consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 2 Variable Interest Entities.

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

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

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Pepco Holdings LLC and Subsidiary Companies

Consolidated Statements of Changes in Equity

(In millions, except share data) *Predecessor*	**Common Stock** [(a)]	**Retained Earnings**	**Accumulated Other Comprehensive Loss, net**	**Total Shareholders Equity**
Balance, December 31, 2013	$ 3,754	$ 595	$ (34)	$ 4,315
Net income		242		242
Common stock dividends		(272)		(272)
Original issue shares, net	14			14
DRP original issue shares	28			28
Net activity related to stock-based awards	7			7
Other comprehensive loss, net of income taxes			(12)	(12)
Balance, December 31, 2014	$ 3,803	$ 565	$ (46)	$ 4,322
Net income		327		327
Common stock dividends		(275)		(275)
Original issue shares, net	15			15
DRP original issue shares	11			11
Net activity related to stock-based awards	3			3
Other comprehensive income, net of income taxes			10	10
Balance, 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, March 23, 2016	$ 3,838	$ 636	$ (35)	$ 4,439

Successor	**Membership Interest**	**Undistributed Losses**	**Accumulated Other Comprehensive Loss, net**	**Member s Equity**
Balance, March 24, 2016 [(b)]	$ 7,200	$	$	$ 7,200
Net loss		(61)		(61)
Distribution to member [(c)]	(400)			(400)
Contribution from member	1,251			1,251
	35			35

Measurement period adjustment of Exelon s deferred tax liabilities to reflect unitary state income tax consequences of the merger								
Distribution of net retirement benefit obligation to member		53						53
Assumption of member liabilities [d]		(62)						(62)
Balance, December 31, 2016	$	8,077	$	(61)	$		$	8,016

(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 $165 million of cash, each of which were distributed by PHI to Exelon.

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

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Potomac Electric Power Company

Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$ 2,181	$ 2,124	$ 2,050
Operating revenues from affiliates	5	5	5
Total operating revenues	2,186	2,129	2,055
Operating expenses			
Purchased power	411	719	735
Purchased power from affiliates	295		
Operating and maintenance	607	435	386
Operating and maintenance from affiliates	35	4	4
Depreciation and amortization	295	256	212
Taxes other than income	377	376	369
Total operating expenses	2,020	1,790	1,706
Gain on sales of assets	8	46	
Operating income	174	385	349
Other income and (deductions)			
Interest expense, net	(127)	(124)	(115)
Other, net	36	28	30
Total other income and (deductions)	(91)	(96)	(85)
Income before income taxes	83	289	264
Income taxes	41	102	93
Net income attributable to common shareholder	$ 42	$ 187	$ 171
Comprehensive income	$ 42	$ 187	$ 171

See the Combined Notes to Consolidated Financial Statements

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Potomac Electric Power Company

Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net income	$ 42	$ 187	$ 171
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation and amortization	295	256	212
Gain on sales of assets	(8)	(46)	
Deferred income taxes and amortization of investment tax credits	153	150	175
Other non-cash operating activities	183	54	37
Changes in assets and liabilities:			
Accounts receivable	(41)	(43)	7
Receivables from and payables to affiliates, net	44		(2)
Inventories	1	(5)	5
Accounts payable and accrued expenses	32	(21)	(37)
Income taxes	110	(46)	(14)
Pension and non-pension postretirement benefit contributions	(32)	(14)	(11)
Other assets and liabilities	(128)	(99)	(157)
Net cash flows provided by operating activities	651	373	386
Cash flows from investing activities			
Capital expenditures	(586)	(544)	(567)
Proceeds from sale of long-lived asset	12	54	9
Purchases of investments	(30)		
Changes in restricted cash	(31)	3	(3)
Other investing activities	(12)	10	1
Net cash flows used in investing activities	(647)	(477)	(560)
Cash flows from financing activities			
Changes in short-term borrowings	(41)	(40)	(47)
Issuance of long-term debt	4	208	412
Retirement of long-term debt	(11)	(22)	(184)
Dividends paid on common stock	(136)	(146)	(86)
Contribution from parent	187	112	80
Other financing activities	(3)	(9)	(4)
Net cash flows provided by financing activities		103	171
Increase (decrease) in cash and cash equivalents	4	(1)	(3)

Cash and cash equivalents at beginning of period	5	6	9
Cash and cash equivalents at end of period	$ 9	$ 5	$ 6

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Potomac Electric Power Company

Balance Sheets

(In millions)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 9	$ 5
Restricted cash and cash equivalents	33	2
Accounts receivable, net		
Customer	235	230
Other	150	261
Inventories, net	63	67
Regulatory assets	162	140
Other	32	21
Total current assets	684	726
Property, plant and equipment, net	5,571	5,162
Deferred debits and other assets		
Regulatory assets	690	661
Investments	102	68
Prepaid pension asset	282	287
Other	6	4
Total deferred debits and other assets	1,080	1,020
Total assets	$ 7,335	$ 6,908

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Potomac Electric Power Company

Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$ 23	$ 64
Long-term debt due within one year	16	11
Accounts payable	209	145
Accrued expenses	113	119
Payables to affiliates	74	30
Customer deposits	53	46
Regulatory liabilities	11	15
Merger related obligation	68	
Other	29	25
Total current liabilities	596	455
Long-term debt	2,333	2,340
Deferred credits and other liabilities		
Regulatory liabilities	20	29
Deferred income taxes and unamortized investment tax credits	1,910	1,723
Non-pension postretirement benefit obligations	43	49
Other	133	72
Total deferred credits and other liabilities	2,106	1,873
Total liabilities	5,035	4,668
Commitments and contingencies		
Shareholder s equity		
Common stock	1,309	1,122
Retained earnings	991	1,118
Total shareholder s equity	2,300	2,240
Total liabilities and shareholder s equity	$ 7,335	$ 6,908

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Potomac Electric Power Company

Statements of Changes in Shareholder s Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2013	$ 930	$ 992	$ 1,922
Net income		171	171
Common stock dividends		(86)	(86)
Contribution from Parent	80		80
Balance, December 31, 2014	$ 1,010	$ 1,077	$ 2,087
Net income		187	187
Common stock dividends		(146)	(146)
Contribution from Parent	112		112
Balance, December 31, 2015	$ 1,122	$ 1,118	$ 2,240
Net income		42	42
Common stock dividends		(169)	(169)
Contribution from Parent	187		187
Balance, December 31, 2016	$ 1,309	$ 991	$ 2,300

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Delmarva Power & Light Company

Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$ 1,122	$ 1,132	$ 1,081
Natural gas operating revenues	148	164	194
Operating revenues from affiliates	7	6	7
Total operating revenues	1,277	1,302	1,282
Operating expenses			
Purchased power	369	555	536
Purchased fuel	60	79	104
Purchased power from affiliate	154		
Operating and maintenance	422	303	266
Operating and maintenance from affiliates	19	1	1
Depreciation, amortization and accretion	157	148	122
Taxes other than income	55	51	46
Total operating expenses	1,236	1,137	1,075
Gain on sales of assets	9		
Operating income	50	165	207
Other income and (deductions)			
Interest expense, net	(50)	(50)	(48)
Other, net	13	10	10
Total other income and (deductions)	(37)	(40)	(38)
Income before income taxes	13	125	169
Income taxes	22	49	65
Net (loss) income attributable to common shareholder	$ (9)	$ 76	$ 104
Comprehensive (loss) income	$ (9)	$ 76	$ 104

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Delmarva Power & Light Company

Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2016	2015	2014
Cash flows from operating activities			
Net (loss) income	$ (9)	$ 76	$ 104
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:			
Depreciation, amortization, and accretion	157	148	122
Deferred income taxes and amortization of investment tax credits	109	73	110
Other non-cash operating activities	114	33	22
Changes in assets and liabilities:			
Accounts receivable	(5)	(24)	1
Receivables from and payables to affiliates, net	13	3	(6)
Inventories		6	(2)
Accounts payable and accrued expenses	(4)	(8)	
Collateral (paid) received, net	1	(1)	
Income taxes	28	(26)	(1)
Pension and non-pension postretirement benefit contributions	(22)		
Other assets and liabilities	(72)	(14)	(82)
Net cash flows provided by operating activities	310	266	268
Cash flows from investing activities			
Capital expenditures	(349)	(352)	(352)
Proceeds from sales of long-lived assets	9		
Change in restricted cash		5	(5)
Other investing activities	4	2	(1)
Net cash flows used in investing activities	(336)	(345)	(358)
Cash flows from financing activities			
Change in short-term borrowings	(105)	(1)	(41)
Issuance of long-term debt	175	200	204
Retirement of long-term debt	(100)	(100)	(100)
Dividends paid on common stock	(54)	(92)	(100)
Contribution from parent	152	75	130
Other financing activities	(1)	(2)	(1)
Net cash flows provided by financing activities	67	80	92
Increase in cash and cash equivalents	41	1	2
Cash and cash equivalents at beginning of period	5	4	2

Cash and cash equivalents at end of period	$ 46	$ 5	$ 4

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Delmarva Power & Light Company

Balance Sheets

(In millions)	December 31, 2016	2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 46	$ 5
Accounts receivable, net		
Customer	136	154
Other	63	96
Receivables from affiliates	3	
Inventories, net		
Gas held in storage	7	8
Materials and supplies	32	32
Regulatory assets	59	72
Other	24	21
Total current assets	370	388
Property, plant and equipment, net	3,273	3,070
Deferred debits and other assets		
Regulatory assets	289	299
Goodwill	8	8
Prepaid pension asset	206	202
Other	7	2
Total deferred debits and other assets	510	511
Total assets	$ 4,153	$ 3,969

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Delmarva Power & Light Company

Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$	$ 105
Long-term debt due within one year	119	204
Accounts payable	88	109
Accrued expenses	36	31
Payables to affiliates	38	20
Customer deposits	36	31
Regulatory liabilities	43	49
Merger related obligation	13	
Other	8	15
Total current liabilities	381	564
Long-term debt	1,221	1,061
Deferred credits and other liabilities		
Regulatory liabilities	97	111
Deferred income taxes and unamortized investment tax credits	1,056	945
Non-pension postretirement benefit obligations	19	19
Other	53	32
Total deferred credits and other liabilities	1,225	1,107
Total liabilities	2,827	2,732
Commitments and contingencies		
Shareholder s equity		
Common stock	764	612
Retained earnings	562	625
Total shareholder s equity	1,326	1,237
Total liabilities and shareholder s equity	$ 4,153	$ 3,969

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Delmarva Power & Light Company

Statements of Changes in Shareholder s Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2013	$ 407	$ 637	$ 1,044
Net income		104	104
Common stock dividends		(100)	(100)
Contribution from parent	130		130
Balance, December 31, 2014	$ 537	$ 641	$ 1,178
Net income		76	76
Common stock dividends		(92)	(92)
Contribution from parent	75		75
Balance, December 31, 2015	$ 612	$ 625	$ 1,237
Net loss		(9)	(9)
Common stock dividends		(54)	(54)
Contribution from parent	152		152
Balance, December 31, 2016	$ 764	$ 562	$ 1,326

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company

Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2016	2015	2014
Operating revenues			
Electric operating revenues	$ 1,254	$ 1,291	$ 1,206
Operating revenues from affiliates	3	4	4
Total operating revenues	1,257	1,295	1,210
Operating expenses			
Purchased power	614	708	664
Purchased power from affiliates	37		
Operating and maintenance	410	268	247
Operating and maintenance from affiliates	18	3	3
Depreciation, amortization and accretion	165	175	155
Taxes other than income	7	7	4
Total operating expenses	1,251	1,161	1,073
Gain on sale of assets	1		
Operating income	7	134	137
Other income and (deductions)			
Interest expense, net	(62)	(64)	(64)
Other, net	9	3	3
Total other income and (deductions)	(53)	(61)	(61)
(Loss) income before income taxes	(46)	73	76
Income taxes	(4)	33	30
Net (loss) income attributable to common shareholder	$ (42)	$ 40	$ 46
Comprehensive (loss) income	$ (42)	$ 40	$ 46

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company

Consolidated Statements of Cash Flows

(In millions)	**For the Years Ended December 31, 2016**	**2015**	**2014**
Cash flows from operating activities			
Net (loss) income	$ (42)	$ 40	$ 46
Adjustments to reconcile net (loss) income to net cash from operating activities:			
Depreciation, amortization and accretion	165	175	155
Deferred income taxes and amortization of investment tax credits	22	31	38
Other non-cash operating activities	155	37	26
Changes in assets and liabilities:			
Accounts receivable	(8)	(67)	6
Receivables from and payables to affiliates, net	13	1	
Inventories	(1)	(1)	4
Accounts payable, accrued expenses and other current liabilities	9	9	(17)
Income taxes	174	(34)	(20)
Pension and non-pension postretirement benefit contributions	(17)	(2)	(3)
Other assets and liabilities	(85)	67	24
Net cash flows provided by operating activities	385	256	259
Cash flows from investing activities			
Capital expenditures	(311)	(300)	(225)
Proceeds from sale of long-lived assets	2		
Changes in restricted cash	(2)	(6)	
Other investing activities	2		1
Net cash flows used in investing activities	(309)	(306)	(224)
Cash flows from financing activities			
Change in short-term borrowings	(5)	(122)	7
Issuance of long-term debt		150	150
Retirement of long-term debt	(48)	(58)	(66)
Repayment of term loan			(100)
Dividends paid on common stock	(63)	(12)	(26)
Contributions from parent	139	95	
Other financing activities	(1)	(2)	(1)
Net cash flows provided by (used in) financing activities	22	51	(36)
Increase (decrease) in cash and cash equivalents	98	1	(1)
Cash and cash equivalents at beginning of period	3	2	3

Cash and cash equivalents at end of period	$ 101	$ 3	$ 2

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Atlantic City Electric Company and Subsidiary Company

Consolidated Balance Sheets

(In millions)	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash and cash equivalents	$ 101	$ 3
Restricted cash and cash equivalents	9	12
Accounts receivable, net		
Customer	125	156
Other	44	242
Inventories, net	22	23
Regulatory assets	96	98
Other	2	12
Total current assets	399	546
Property, plant and equipment, net	2,521	2,322
Deferred debits and other assets		
Regulatory assets	405	414
Long-term note receivable	4	4
Prepaid pension asset	84	82
Other	44	19
Total deferred debits and other assets	537	519
Total assets [(a)]	$ 3,457	$ 3,387

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company

Consolidated Balance Sheets

(In millions)	December 31, 2016	2015
LIABILITIES AND SHAREHOLDER S EQUITY		
Current liabilities		
Short-term borrowings	$	$ 5
Long-term debt due within one year	35	48
Accounts payable	132	96
Accrued expenses	38	70
Payables to affiliates	29	16
Customer deposits	33	30
Regulatory liabilities	25	18
Merger related obligation	20	
Other	8	14
Total current liabilities	320	297
Long-term debt	1,120	1,153
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	917	885
Non-pension postretirement benefit obligations	34	33
Regulatory liabilities		7
Other	32	12
Total deferred credits and other liabilities	983	937
Total liabilities [(a)]	2,423	2,387
Commitments and contingencies		
Shareholder s equity		
Common stock	912	773
Retained earnings	122	227
Total shareholder s equity	1,034	1,000
Total liabilities and shareholder s equity	$ 3,457	$ 3,387

(a) ACE s consolidated assets include $32 million and $30 million at December 31, 2016 and 2015, respectively, of ACE s consolidated VIE that can only be used to settle the liabilities of the VIE. ACE s consolidated liabilities include $126 million and $172 million at December 31, 2016 and 2015, respectively, of ACE s consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 2 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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Atlantic City Electric Company and Subsidiary Company

Consolidated Statements of Changes in Shareholder s Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder s Equity
Balance, December 31, 2013	$ 678	$ 179	$ 857
Net income		46	46
Common stock dividends		(26)	(26)
Balance, December 31, 2014	$ 678	$ 199	$ 877
Net income		40	40
Common stock dividends		(12)	(12)
Contribution from parent	95		95
Balance, December 31, 2015	$ 773	$ 227	$ 1,000
Net loss		(42)	(42)
Common stock dividends		(63)	(63)
Contribution from parent	139		139
Balance, December 31, 2016	$ 912	$ 122	$ 1,034

See the Combined Notes to Consolidated Financial Statements

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Combined Notes to Consolidated Financial Statements

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

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**
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. Generation also sells renewable energy and other energy-related products and services. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

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

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

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

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Combined Notes to Consolidated Financial Statements (Continued)

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

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

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

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

Basis of Presentation (All Registrants)

This is a combined annual report of all registrants. The Notes to the Consolidated Financial Statements apply to the registrants as indicated above in the Index to Combined Notes to Consolidated Financial Statements and parenthetically next to each corresponding disclosure. When appropriate, the registrants are named specifically for their related activities and disclosures.

Each of the Registrant s Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. All Equity in earnings (losses) from unconsolidated affiliates have been presented below Income taxes in the Registrants Consolidated Statements of Operations and Comprehensive Income starting in the first quarter of 2015.

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.

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon s corporate operations are presented as Other within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

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Combined Notes to Consolidated Financial Statements (Continued)

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

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, accounting, engineering, distribution and transmission planning, asset management, system operations, and power procurement, to PHI and its operating subsidiaries. These services are directly charged or allocated pursuant to service agreements among PHI Service Company and the participating operating subsidiaries.

Exelon owns 100% of all of its significant consolidated subsidiaries, including PHI, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%. As of December 31, 2016, Exelon owned none of BGE s preferred securities, which BGE redeemed in 2016. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2016 and December 31, 2015, as equity, and BGE s preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters. PHI is subject to some ring-fencing measures established by orders of the DCPSC, DPSC, MDPSC and NJBPU, pursuant to which all of the membership interest in PHI is held directly by PH Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (PH Utility), Inc., an unrelated party, holds a nominal non-economic interest in PH Holdco LLC with limited voting rights on specified matters. PHI owns 100% of its subsidiaries including Pepco, DPL and ACE.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for certain variable interest entities, including CENG, of which Generation holds a 50.01% interest. The remaining interests are included in noncontrolling interests on Exelon s and Generation s Consolidated Balance Sheets. See Note 2 Variable Interest Entities for further discussion of Exelon s and Generation s consolidated VIEs.

The Registrants consolidate the accounts of entities in which a Registrant has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which the Registrant can exercise control over the operations and policies of the investee, or the results of a model that identifies the Registrant or one of its subsidiaries as the primary beneficiary of a VIE. Where the Registrants do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or cost method accounting is applied. The Registrants apply proportionate consolidation when they have an undivided interest in an asset and are proportionately liable for their share of each liability associated with the asset. The Registrants proportionately consolidate their undivided ownership interests in jointly owned electric plants and transmission facilities. Under proportionate consolidation, the Registrants separately record their proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. The Registrants apply equity method accounting when they have significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. The Registrants apply equity method accounting to certain investments and joint ventures, including certain financing trusts of ComEd, PECO and BGE. Under the equity method, the Registrants report their interest in the entity as an investment and the Registrants percentage share of the earnings from the entity as single line items in their financial statements. The Registrants use the cost method if they lack significant influence, which generally results when they hold less than 20% of the common stock of an entity. Under the cost method, the Registrants report their investments at cost and recognize income only to the extent dividends or distributions are received.

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Combined Notes to Consolidated Financial Statements (Continued)

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

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Use of Estimates (All Registrants)

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (All Registrants)

Certain prior year amounts in the Registrants Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets and Consolidated Statements of Cash Flows have been reclassified between line items for comparative purposes. The reclassifications did not affect any of the Registrants net income, financial positions, or cash flows from operating activities.

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 in the prior financial statements.

Accounting for the Effects of Regulation (Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE)

The Registrants apply the authoritative guidance for accounting for certain types of regulation, which requires them to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities cost of providing services or products; and (3) there is a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Exelon and the Utility Registrants account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, the MDPSC, the DCPSC, the DPSC and the NJBPU, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense or revenue is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. Exelon and the Utility Registrants continue to

Combined Notes to Consolidated Financial Statements (Continued)

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

evaluate their respective abilities to continue to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of the Registrants business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3 Regulatory Matters for additional information.

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 $2 million and $1 million for the years ended December 31, 2015 and December 31, 2014, respectively.

The Registrants treat the impacts of a final rate order received after the balance sheet date but prior to the issuance of the financial statements as a non-recognized subsequent event, as the receipt of a final rate order is a separate and distinct event that has future impacts on the parties affected by the order.

Revenues (All Registrants)

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco, DPL and ACE record their best estimate of the transmission revenue impacts resulting from changes in rates that they each believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 3 Regulatory Matters and Note 6 Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations and Comprehensive Income, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. To the

Combined Notes to Consolidated Financial Statements (Continued)

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

extent a Utility Registrant receives full cost recovery for energy procurement and related costs from retail customers, it records the fair value of its energy swap contracts with unaffiliated suppliers as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. Refer to Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation s trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the Consolidated Statements of Operations and Comprehensive Income. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 13 Derivative Financial Instruments for further information.

Income Taxes (All Registrants)

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on the Registrants Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion; and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in Interest expense or Other income and deductions (interest income) and recognize penalties related to unrecognized tax benefits in Other, net on their Consolidated Statements of Operations and Comprehensive Income.

In the first quarter of 2016, PHI, Pepco, DPL and ACE changed their accounting 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 year ended December 31, 2015 is $34 million and $4 million for PHI and Pepco, respectively, and for the year ended December 31, 2014 is $1 million for both Pepco and ACE. The impact on all other PHI Registrants for years ended December 31, 2015 and December 31, 2014 is less than $1 million.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 15 Income Taxes for further information.

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Combined Notes to Consolidated Financial Statements (Continued)

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

Taxes Directly Imposed on Revenue-Producing Transactions (All Registrants)

The Registrants collect certain taxes from customers such as sales and gross receipts taxes, along with other taxes, surcharges and fees that are levied by state or local governments on the sale or distribution of gas and electricity. Some of these taxes are imposed on the customer, but paid by the Registrants, while others are imposed on the Registrants. Where these taxes are imposed on the customer, such as sales taxes, they are reported on a net basis with no impact to the Consolidated Statements of Operations and Comprehensive Income. However, where these taxes are imposed on the Registrants, such as gross receipts taxes or other surcharges or fees, they are reported on a gross basis. Accordingly, revenues are recognized for the taxes collected from customers along with an offsetting expense. See Note 25 Supplemental Financial Information for Generation s, ComEd s, PECO s, BGE s, Pepco s, DPL s and ACE s utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (All Registrants)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Cash Equivalents (All Registrants)

Restricted cash and cash equivalents represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2016 and 2015, Exelon Corporate s restricted cash and cash equivalents primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Generation s restricted cash and cash equivalents primarily included cash at various project-specific non-recourse financing structures for debt service and financing of operations of the underlying entities, see Note 14 Debt and Credit Agreements for additional information on Generation s project- specific financing structures. ComEd s restricted cash primarily represented cash collateral held from suppliers associated with ComEd s energy and REC procurement contracts. PECO s restricted cash primarily represented funds from the sales of assets that were subject to PECO s mortgage indenture. BGE s restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds and cash collateral held from suppliers. PHI Corporate s restricted cash and cash equivalents primarily represented funds restricted for the payment of merger commitments and cash collateral held from its utility suppliers. Pepco s restricted cash and cash equivalents primarily represented funds restricted for the payment of merger commitments and collateral held from its utility suppliers. DPL s restricted cash and cash equivalents primarily represented cash collateral held from suppliers associated with procurement contracts. ACE s restricted cash and cash equivalents primarily represented funds restricted at its consolidated variable interest entity for repayment of transition bonds and cash collateral held from suppliers.

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2016 and 2015, Exelon s and Generation s NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2016, Exelon, Generation, ComEd, PECO, BGE, PHI and Pepco had investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts (All Registrants)

The allowance for uncollectible accounts reflects the Registrants   best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging

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Combined Notes to Consolidated Financial Statements (Continued)

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

historical experience and other currently available information. ComEd, PECO and BGE estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. At December 31, 2015, Pepco, DPL and ACE estimated the allowance for uncollectible accounts based on specific identification of material amounts at risk by customer and maintained a reserve based on their historical collection experience. At December 31, 2016, Pepco, DPL and ACE aligned the estimation of their allowance for uncollectible accounts to be consistent with ComEd, PECO and BGE, as described above. Risk segments represent a group of customers with similar credit quality indicators that are comprised based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. Utility Registrants customers accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. Utility Registrants customer accounts are written off consistent with approved regulatory requirements. Utility Registrants allowances for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC, MDPSC, DCPSC, DPSC and NJBPU regulations. See Note 3 Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities (All Registrants)

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity has a controlling financial interest, meaning (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,

- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events, and

- requires the entity that consolidates a VIE (the primary beneficiary) to disclose (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

See Note 2 Variable Interest Entities for additional information.

Inventories (All Registrants)

Inventory is recorded at the lower of weighted average cost or net realizable value. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes natural gas held in storage, propane and oil. The costs of natural gas, propane and oil are generally included in inventory when purchased and charged to purchased power and fuel expense at weighted average cost when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, at weighted average cost when installed or used.

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Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and charged to purchased power and fuel expense at weighted average cost as they are used in operations.

Marketable Securities (All Registrants)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities, and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation s NDT funds associated with the Regulatory Agreement Units are included in regulatory liabilities at Exelon, ComEd and PECO and in Noncurrent payables to affiliates at Generation and in Noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation s NDT funds associated with the Non-Regulatory Agreement Units are included in earnings at Exelon and Generation. Unrealized gains and losses, net of tax, for Exelon s available-for-sale securities are reported in OCI. Any decline in the fair value of Exelon s available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 3 Regulatory Matters for additional information regarding ComEd s and PECO s regulatory assets and liabilities and Note 12 Fair Value of Financial Assets and Liabilities and Note 16 Asset Retirement Obligations for information regarding marketable securities held by NDT funds.

Property, Plant and Equipment (All Registrants)

Property, plant and equipment is recorded at original cost. Original cost includes construction-related direct labor and material costs. The Utility Registrants also include indirect construction costs including labor and related costs of departments associated with supporting construction activities. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO, BGE, Pepco, DPL and ACE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse the Utility Registrants for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, plant and equipment. DOE SGIG funds reimbursed to PECO, BGE, Pepco and ACE have been accounted for as CIAC.

For Generation, upon retirement, the cost of property is generally charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to Operating and maintenance expense as incurred.

For the Utility Registrants, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. The Utility Registrants depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility s regulatory recovery method. The Utility

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Registrants   actual incurred removal costs are applied against a related regulatory liability. PECO s removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO s regulatory recovery method.

See Note 7 Property, Plant and Equipment, Note 10 Jointly Owned Electric Utility Plant and Note 25 Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized within Property, plant and equipment and charged to fuel expense using the unit-of-production method. Prior to May 16, 2014, the estimated disposal cost of SNF was established per the Standard Waste Contract with the DOE and was expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. Effective May 16, 2014, the SNF disposal fee was set to zero by the DOE and Exelon and Generation are not accruing any further costs related to SNF disposal fees until a new fee structure goes into effect. Certain on-site SNF storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed. See Note 24 Commitments and Contingencies for additional information regarding the SNF disposal fee.

Nuclear Outage Costs (Exelon and Generation)

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs (Exelon and Generation)

New site development costs represent the costs incurred in the assessment and design of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management s determination that the project is economically and operationally feasible, management and/or the Exelon board of directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. As of December 31, 2016 and 2015, Generation has capitalized $1.7 billion and $1.3 billion, respectively, to Property, plant and equipment, net on its Consolidated Balance Sheets. Capitalized development costs are charged to Operating and maintenance expense when project completion is no longer probable. New site development costs incurred prior to a project s completion being deemed probable are expensed as incurred. Approximately $30 million, $22 million and $13 million of costs were expensed by Exelon and Generation for the years ended December 31, 2016, 2015, and 2014, respectively. These costs are primarily related to the possible development of new power generating facilities with the exception of approximately $13 million of costs expensed in 2016 which relate to projects for which completion is no longer probable.

Capitalized Software Costs (All Registrants)

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized within property, plant, and equipment. Such

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capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2016	$ 808	$ 173	$ 213	$ 91	$ 164	$ 1	$ 1	$ 1
December 31, 2015	633	180	172	86	178		1	1

Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
2016	$ 255	$ 72	$ 62	$ 33	$ 44	$	$	$
2015	208	73	47	33	46	(2)		
2014	186	59	45	28	43	2		

	Successor	*Predecessor*
PHI	**December 31, 2016**	**December 31, 2015**
Net unamortized software costs	$ 153	$ 172

	Successor	*Predecessor*		
PHI	**March 24, 2016 to December 31, 2016**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
Amortization of capitalized software costs	$ 29	$ 8	$ 36	$ 30

Depreciation, Depletion and Amortization (All Registrants)

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method in which depreciation is calculated using the average estimated service life of assets within a group. The Utility Registrants depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility s regulatory recovery method. The estimated service lives for the Utility Registrants are primarily based on each company s most recent depreciation studies of historical asset retirement and removal cost experience. At Generation, along with depreciation study results, management considers expected future energy market conditions and generation plant operating costs and capital investment requirements in determining the estimated service lives of its generating facilities. For its nuclear generating facilities, except for Oyster Creek and Clinton, Generation estimates each unit will operate through the full term of its initial 20-year operating license renewal period. See Note 9 Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirements. The estimated service lives of Generation s hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of 40 years.

See Note 7 Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets and liabilities are recorded over the recovery or refund period specified in the related legislation or regulatory order or agreement. When the recovery or refund period is less than one year, amortization is recorded to the line item in which the deferred cost or income would have originally been recorded in the Registrants Consolidated Statements of Operations

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and Comprehensive Income. Amortization of ComEd s distribution formula rate regulatory asset and ComEd s, BGE s, Pepco s, DPL s and ACE s transmission formula rate regulatory assets is recorded to Operating revenues.

Amortization of income tax related regulatory assets and liabilities are generally recorded to Income tax expense. With the exception of the regulatory assets and liabilities discussed above, when the recovery period is more than one year, the amortization is generally recorded to Depreciation and amortization in the Registrants Consolidated Statements of Operations and Comprehensive Income.

See Note 3 Regulatory Matters and Note 25 Supplemental Financial Information for additional information regarding Generation s nuclear fuel, Generation s ARC and the amortization of the Utility Registrants regulatory assets.

Asset Retirement Obligations (All Registrants)

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, 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 future cash flow models and discount rates. Generation generally 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 decommissioning scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation s nuclear units at least every five years unless circumstances warrant more frequent updates (such as a change in assumed operating life for a nuclear plant). As part of the annual cost study update process, Generation evaluates newly assumed costs or substantive changes in previously assumed costs to determine if the cost estimate impacts are sufficiently material to warrant application of the updated estimates to the AROs across the nuclear fleet outside of the normal five-year rotating cost study update cycle. The liabilities associated with Exelon s non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years unless circumstances warrant more frequent updates. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimated undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted throughout each year to reflect the time value of money for these present value obligations through a charge to Operating and maintenance expense in the Consolidated Statements of Operations and Comprehensive Income or, in the case of the Utility Registrants accretion, through an increase to regulatory assets. See Note 16 Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (All Registrants)

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations.

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AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon [a]	Generation [a]	ComEd	PECO	BGE	Pepco	DPL	ACE
2016	Total incurred interest [b]	$ 1,678	$ 472	$ 469	$ 127	$ 114	$ 137	$ 52	$ 65
	Capitalized interest	108	107						
	Credits to AFUDC debt and equity	98		22	11	30	29	7	9
2015	Total incurred interest [b]	$ 1,170	$ 445	$ 336	$ 116	$ 113	$ 131	$ 51	$ 65
	Capitalized interest	79	79						
	Credits to AFUDC debt and equity	44		9	7	28	19	2	2
2014	Total incurred interest [b]	$ 1,144	$ 419	$ 323	$ 115	$ 118	$ 121	$ 49	$ 65
	Capitalized interest	63	63						
	Credits to AFUDC debt and equity	37		5	8	24	16	3	2

	Successor	*Predecessor*		
PHI	**March 24, 2016 to December 31, 2016**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**	**For the Year Ended December 31, 2014**
Total incurred interest [b]	$ 207	$ 68	$ 289	$ 277
Credits to AFUDC debt and equity	35	10	23	21

(a) On April 1, 2014, Generation assumed operational control of CENG s nuclear fleet. As a result, the 2014 financial results include CENG s financial position and results of operations beginning April 1, 2014.
(b) Includes interest expense to affiliates.

Guarantees (All Registrants)

The Registrants recognize, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken by issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 24 Commitments and Contingencies for additional information.

Asset Impairments (All Registrants)

Long-Lived Assets. The Registrants evaluate the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may

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not be recoverable. Indicators of impairment may include a deteriorating business climate, including, but not limited to, declines in energy prices, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life. The Registrants determine if long-lived assets and asset groups are impaired by comparing the undiscounted expected future cash flows to the carrying value. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value less costs to sell.

Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generating units are generally evaluated at a regional portfolio level along with cash flows generated from the customer supply and risk management activities, including cash flows from related intangible assets and liabilities on the balance sheet. In certain cases, generating assets may be evaluated on an individual basis where those assets are contracted on a long-term basis with a third party and operations are independent of other generation assets (typically contracted renewables). See Note 8 Impairment of Long-Lived Assets for additional information.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 11 Intangible Assets for additional information regarding Exelon s, Generation s, ComEd s and PHI s goodwill.

Equity Method Investments. Exelon and Generation regularly monitor and evaluate equity method investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other-than-temporary decline in value.

Debt and Equity Security Investments. Exelon and Generation regularly monitor and evaluate debt and equity investments to determine whether they are impaired. An impairment is recorded when the investment has experienced a decline in value that is other-than-temporary in nature.

Derivative Financial Instruments (All Registrants)

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that are not

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designated or do not qualify for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period, except for the Utility Registrants where changes in fair value may be recorded as a regulatory asset or liability if there is an ability to recover or return the associated costs. See Note 3 Regulatory Matters and Note 13 Derivative Financial Instruments for additional information. Amounts classified in earnings are included in revenue, purchased power and fuel, interest expense or other, net on the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon s Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statements of Operations and Comprehensive Income. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For commodity derivative contracts Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the March 2012 merger of Exelon and Constellation. Because the underlying forecasted transactions at that time remained probable, the fair value of the effective portion of these cash flow hedges was frozen in AOCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred through March 31, 2015. Accordingly, all derivatives executed to hedge economic risk related to commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

As part of Generation s energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. See Note 13 Derivative Financial Instruments for additional information.

Retirement Benefits (All Registrants)

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

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and inputs and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the Consolidated Statements of Operations and Comprehensive Income. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 17 Retirement Benefits for additional information.

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Equity Investment Earnings (Losses) of Unconsolidated Affiliates (Exelon and Generation)

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, in equity in earnings (losses) of unconsolidated affiliates within their Consolidated Statements of Operations and Comprehensive Income. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between the cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment.

New Accounting Standards (All Registrants)

New Accounting Standards Adopted: in 2016 the Registrants have adopted the following new authoritative accounting guidance issued by the FASB. Unless otherwise indicated, adoption of the guidance in each instance had no or insignificant impacts on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows and disclosures.

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (Issued May 2015; Adopted first quarter 2016 retrospectively to all prior periods presented): 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, and instead provides for such investments to be disclosed 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. See Note 12 Fair Value of Financial Assets and Liabilities for the disclosure impacts.

Customer s Accounting for Fees Paid in a Cloud Computing Arrangement (Issued April 2015; Adopted first quarter 2016 prospectively): 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.

Amendments to the Consolidation Analysis (Issued February 2015; Adopted January 1, 2016): Amends the consolidation analysis for variable interest entities (VIEs) and 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 Registrants did not revise any consolidation conclusions as a result of the guidance, but did identify additional entities that are now considered VIEs. See Note 2 Variable Interest Entities for the associated disclosures.

Simplifying the Transition to the Equity Method of Accounting (Issued March 2016; Early adopted fourth quarter 2016): Eliminates the requirement to retroactively adopt the equity method of accounting as a result of an increase in the level ownership or degree of influence of an existing investment.

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Instead, an investor now adds the cost of acquiring the additional interest in the investee to the current basis of the investor s previously held interest and adopts the equity method of accounting as of the date the investment qualifies for such treatment.

Effect of Derivative Contract Novations on Existing Hedge Accounting Relationships (Issued March 2016; Early adopted fourth quarter 2016 prospectively): 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.

Simplifying the Measurement of Inventory (Issued July 2015; Early adopted fourth quarter 2016 prospectively): Requires inventory to be measured at the lower of cost or net realizable value, with net realizable value defined 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.

Contingent Put and Call Options in Debt Instruments (Issued March 2016; Adopted January 1, 2017 on a modified retrospective basis): 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 guidance is required to be applied on a modified retrospective basis to all existing and future debt instruments.

Interests Held through Related Parties that are Under Common Control (Issued October 2016; Adopted January 1, 2017 on a retrospective basis to January 1, 2016): Requires consideration of indirect interests held through related parties under common control proportionately when determining whether an entity is the primary beneficiary of a variable interest entity.

Improvements to Employee Share-Based Payment Accounting (Issued March 2016; Adopted January 1, 2017 using either the prospective, modified retrospective, or retrospective method as prescribed by the standard): Simplifies various aspects of 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.

New Accounting Standards Issued and Not Yet Adopted: The following new authoritative accounting guidance issued by the FASB has not yet been adopted and reflected by the Registrants in their consolidated financial statements. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures, as well as the potential to early adopt where applicable. The Registrants have assessed other FASB issuances of new standards which are not listed below given the current expectation such standards will not significantly impact the Registrants financial reporting.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions): Changes the criteria for recognizing revenue from a contract with a

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customer. The new revenue recognition guidance, including subsequent amendments, is effective for annual reporting periods beginning on or after December 15, 2017, with the option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants do not plan to early adopt the standard.

The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. In addition, the Registrants will be required to capitalize costs to acquire new contracts, and amortize such costs in a manner consistent with the transfer to the customer of the associated goods or services. Exelon currently expenses those costs as incurred. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method).

The Registrants continue to assess the impacts this guidance may have on their Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. In performing this assessment, the Registrants have utilized a project implementation team comprised of both internal and external resources to conduct the following key activities:

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

- Evaluate existing contracts and revenue streams for potential changes in the amounts and timing of recognizing revenues under the new guidance;

- Evaluate and select the transition method; and

- Develop and implement the approach and process for complying with the new revenue recognition disclosure requirements.

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

The Registrants expect to apply the new guidance using the full retrospective method, however this conclusion could change based on the outcome of open implementation issues discussed below;

The Registrants currently anticipate that the implementation of the new guidance will not have a material impact on the amount and timing of revenue recognition; and

The Registrants expect the new guidance will result in more detailed disclosures of revenue compared to current guidance.

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Notwithstanding the preliminary conclusions noted above, certain implementation issues continue to be debated and worked through the Industry Task Force process that could result in amendments to the standard or implementation guidance that could have a material impact on the Registrants Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows and disclosures. The open implementation issues that could be most impactful to the Registrants include: (1) the ability of the Utility Registrants to recognize revenue for certain contracts where collectability is in question, (2) the accounting by the Utility Registrants for contributions in aid of construction (CIAC) and whether CIAC arrangements are within the scope of the revenue guidance and (3) primarily at Generation, bundled sales contracts and contracts with pricing provisions that may require recognition of revenue at prices other than the contract price (e.g., straight line or estimated future market prices). As part of the overall implementation project, the Registrants are developing alternative adoption plans that would be implemented in the event the ultimate resolution of the open implementation issues result in significant changes from current revenue recognition practices.

Leases (Issued February 2016): Increases transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The 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. Early adoption is permitted, however the Registrants do not expect to early adopt the standard. Lessees and lessors are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. Refer to Note 24 Commitments and Contingencies for additional information regarding operating leases.

Impairment of Financial Instruments (Issued June 2016): Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity s current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 and, for most debt instruments, requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption.

Goodwill Impairment (issued January 2017): Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit s carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two step impairment test). Entities will continue to have the option to perform a

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qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, ComEd, Generation, and DPL have goodwill as of December 31, 2016. This updated guidance is not currently expected to impact the Registrants financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be adopted on a prospective basis.

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

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

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

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016): (i) requires all investments in equity securities, including other ownership interests such as partnerships, unincorporated joint ventures and limited liability companies, to be carried at fair value through net income, (ii) requires an incremental recognition and disclosure requirement related to the presentation of fair value changes of financial liabilities for which the fair value option has been elected, (iii) amends several disclosure requirements, including the methods and significant assumptions used to estimate fair value or a description of the changes in the methods and assumptions used to estimate fair value, and (iv) requires disclosure of the fair value of financial assets and liabilities measured at

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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).

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

Consolidated Variable Interest Entities

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

	December 31, 2016					December 31, 2015				
				Successor					*Predecessor*	
	Exelon (a)(b)	Generation	BGE	PHI (b)	ACE	Exelon (a)	Generation	BGE	PHI	ACE
Current assets	$ 954	$ 916	$ 23	$ 14	9	$ 909	$ 881	$ 23	$ 12	$ 12
Noncurrent assets	8,563	8,525	3	35	23	8,009	8,004	3	18	18
Total assets	$ 9,517	$ 9,441	$ 26	$ 49	$ 32	$ 8,918	$ 8,885	$ 26	$ 30	$ 30
Current liabilities	$ 885	$ 802	$ 42	$ 42	37	$ 473	$ 387	$ 81	$ 48	$ 48
Noncurrent liabilities	2,713	2,612		101	89	2,927	2,884	41	124	124

Total liabilities	$ 3,598	$ 3,414	$ 42	$ 143	$ 126	$ 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.
Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the table can only be settled using VIE resources.

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

RSB BondCo LLC. In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE has determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidates BondCo.

BondCo s assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2016, 2015 and 2014, BGE remitted $86 million, $86 million and $85 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2016. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

ACE Transition Funding. 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. 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 years ended December 31, 2016, 2015 and 2014, ACE transferred $60 million, $61 million and $55 million to ATF, respectively.

Retail Gas Group. During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third-party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group s activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third-party gas supply arrangement is collateralized as follows:

- the assets of the retail gas entity group must be used to settle obligations under the third-party gas supply agreement before it can make any distributions to Generation, the third-party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and

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

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Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third-party gas supply agreement. The third-party gas supply creditors do not have any recourse to Exelon s or Generation s general credit other than the parental guarantee.

Solar Project Entity Group. In 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley) from First Solar, Inc., a 242-MW solar PV project in northern Los Angeles County, California. In addition, Generation owns a number of limited liability companies that build, own, and operate solar power facilities. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and there is limited recourse related to Generation related to certain solar entities. In addition, these solar VIE entities have an aggregate amount of outstanding debt with third parties of $568 million, as of December 31, 2016, for which the creditors have no recourse to Generation. For additional information on these project-specific financing arrangements refer to Note 14 Debt and Credit Agreements.

Retail Power and Gas Companies. In March 2014, Generation began consolidating retail power and gas VIEs for which Generation is the primary beneficiary as a result of energy supply contracts that give Generation the power to direct the activities that most significantly affect the economic performance of the entities. Generation does not have an equity ownership interest in these entities, but provides approximately $21 million in credit support for the retail power and gas companies for which Generation is the sole supplier of energy. These entities are included in Generation s consolidated financial statements, and the consolidation of the VIEs do not have a material impact on Generation s financial results or financial condition.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired during 2010 with the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and the risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling equity interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind generation facilities.

In December 2016, Generation sold approximately 71% of its equity interest in one of its wind projects that was previously consolidated under the voting interest model to a tax equity investor. The wind project was evaluated and it was determined to be 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. While Generation is the minority interest holder, Generation is the primary beneficiary, because Generation manages the day-to-day activities of the entity.

Therefore, the entity continues to be consolidated by Generation.

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While Generation owns 100% of the majority of the wind project entities, six of the projects have noncontrolling equity interests of 1% held by third parties and one of the projects has noncontrolling equity interests of approximately 71%. Regarding the projects with noncontrolling equity interests of 1% held by third parties, Generation s current economic interests in five of these projects is significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the noncontrolling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the noncontrolling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current 99% economic interests in the projects. Generation provides operating and capital funding to the wind project entities for ongoing construction, operations and maintenance of the wind power and there is limited recourse to Generation related to certain wind project entities. However, no additional support to these projects beyond what was contractually required has been provided during 2016. As of December 31, 2016, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relates to the wind generating assets, PPA intangible assets and working capital amounts.

Other Generating Facilities. During the second quarter of 2015, Generation formed a limited liability company to build, own, and operate a backup generator. While Generation owns 100% of the backup generator company, it was determined that the entity is a VIE because the customer absorbs price variability from the entity through the fixed price backup generator agreement. Generation provides operating and capital funding to the backup generator company. Generation also owns 90% of a biomass fueled, combined heat and power company. In the second quarter of 2015, the entity was deemed to be a VIE because the entity requires additional subordinated financial support in the form of a parental guarantee provided by Generation for up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for the facility in support of one of its other generating facilities (see Note 14 Debt and Credit Agreements for additional details on Albany Green Energy, LLC). In addition to the parental guarantee, Generation provides operating and capital funding to the biomass fueled, combined heat and power company. Generation is the primary beneficiary of both entities since Generation has the power to direct the activities that most significantly affect the economic performance of the entities.

CENG. Through March 31, 2014, CENG was operated as a joint venture with EDF and was governed by a board of ten directors, five of which were appointed by Generation and five by EDF. CENG was designed to operate under joint and equal control of Generation and EDF through the Board of Directors, subject to the Chairman of the Board s final decision making authority on certain special matters; therefore, CENG was not subject to VIE guidance. Accordingly, Generation s 50.01% interest in CENG was accounted for as an equity method investment. On April 1, 2014, Generation, CENG, and subsidiaries of CENG executed the Nuclear Operating Services Agreement (NOSA) pursuant to which Generation now conducts all activities associated with the operations of the CENG fleet and provides corporate and administrative services to CENG and the CENG fleet for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF. As a result of executing the NOSA, CENG now qualifies as a VIE due to the disproportionate relationship between Generation s 50.01% equity ownership interest and its role in conducting the operational activities of CENG and the CENG fleet conveyed through the NOSA. Further, since Generation is conducting the operational activities of CENG and the CENG fleet, Generation qualifies as the primary beneficiary of CENG and, therefore, is required to consolidate the financial position and results of operations of CENG. On April 1, 2014, Exelon and Generation

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derecognized Generation s equity method investment in CENG and reflected all assets, liabilities, and the EDF noncontrolling interests in CENG at fair value on the consolidated balance sheets of Exelon and Generation, resulting in the recognition of a $261 million gain in their respective Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2014.

Generation and Exelon, where indicated, provide the following support to CENG (see Note 5 Investment in Constellation Energy Nuclear Group, LLC and Note 27 Related Party Transactions 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 3 Regulatory Matters for additional details),

Generation provided a $400 million loan to CENG. As of December 31, 2016, the remaining obligation is $316 million, including accrued interest, which reflects the principal payment made in January 2015,

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation s obligations under this Indemnity Agreement. (See Note 24 Commitments and Contingencies for more details),

in connection with CENG s severance obligations, Generation reimbursed CENG for a total of approximately $6 million of the severance benefits paid from 2014 through 2016. The final reimbursement was made in 2016, and there was no remaining obligation as of December 31, 2016.

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

Generation provides a guarantee of approximately $7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDF executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

Generation and EDF are the members-insured with Nuclear Electric Insurance Limited and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (See Note 24 Commitments and Contingencies for more details), and

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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.

2015 ESA Investco, LLC. 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 the first quarter of 2017 in proportion to their ownership interests, which is up to $172 million for the tax equity investor and up to $78 million for Generation (see Note 24 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. Pursuant to the new consolidation guidance effective January 1, 2016, 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. Under VIE guidance, Generation is the primary beneficiary; therefore, the entity continues to be consolidated.

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

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

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

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Assets and Liabilities of Consolidated VIEs

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

	December 31, 2016					December 31, 2015				
				Successor					*Predecessor*	
	Exelon [a][b]	Generation	BGE	PHI [b]	ACE	Exelon [a]	Generation	BGE	PHI	ACE
Cash and cash equivalents	$ 150	$ 150	$	$	$	$ 164	$ 164	$	$	$
Restricted cash	59	27	23	9	9	100	77	23	12	12
Accounts receivable, net										
Customer	371	371				219	219			
Other	48	48				43	43			
Mark-to-market derivatives assets	31	31				140	140			
Inventory										
Materials and supplies	199	199				181	181			
Other current assets	50	44		5		35	30			
Total current assets	908	870	23	14	9	882	854	23	12	12
Property, plant and equipment, net	5,415	5,415				5,160	5,160			
Nuclear decommissioning trust funds	2,185	2,185				2,036	2,036			
Goodwill	47	47				47	47			
Mark-to-market derivatives assets	23	23				53	53			
Other noncurrent assets	315	277	3	35	23	90	85	3	18	18
Total noncurrent assets	7,985	7,947	3	35	23	7,386	7,381	3	18	18
Total assets	$ 8,893	$ 8,817	$ 26	$ 49	$ 32	$ 8,268	$ 8,235	$ 26	$ 30	$ 30
Long-term debt due within one year	$ 181	$ 99	$ 41	$ 40	$ 35	$ 111	$ 27	$ 79	$ 46	$ 46
Accounts payable	269	269				216	216			

Accrued expenses	119	116	1	2	2	115	113	2	2	2
Mark-to-market derivative liabilities	60	60				5	5			
Unamortized energy contract liabilities	15	15				12	12			
Other current liabilities	30	30				13	13			
Total current liabilities	674	589	42	42	37	472	386	81	48	48
Long-term debt	641	540		101	89	666	623	41	124	124
Asset retirement obligations	1,904	1,904				1,999	1,999			
Pension obligation[c]	9	9				9	9			
Unamortized energy contract liabilities	22	22				39	39			
Other noncurrent liabilities	106	106				79	79			
Noncurrent liabilities	2,682	2,581		101	89	2,792	2,749	41	124	124
Total liabilities	$ 3,356	$ 3,170	$ 42	$ 143	$ 126	$ 3,264	$ 3,135	$ 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.

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(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 17 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.

As of December 31, 2016 and 2015, Exelon and Generation had significant unconsolidated variable interests in eight VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Generation has several individually immaterial VIEs that in aggregate represent a total investment of $18 million. These immaterial VIEs are equity and debt securities in energy development companies. The maximum exposure to loss related to these securities is limited to the $18 million included in Investments on Exelon s and Generation s Consolidated Balance Sheets.

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

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

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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 $113 million and $206 million as of December 31, 2016 and December 31, 2015, respectively; offset by payables to ZionSolutions LLC of $104 million and $189 million as of December 31, 2016 and December 31, 2015, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

For each unconsolidated VIE, Exelon and Generation 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 agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these variable interest entities.

The Registrants unconsolidated VIEs consist of:

Energy Purchase and Sale Agreements. Generation has several energy purchase and sale agreements with generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each entity, and determined that certain of the entities are VIEs because the entity absorbs risk through the sale of fixed price power and renewable energy credits. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 16 Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning activities under the asset sale agreement are complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required. Other than the asset sale agreement, Exelon and Generation do not have any contractual or other obligations to provide additional financial support and ZionSolutions creditors do not have any recourse to Exelon s or Generation s general credit.

Investment in Energy Development Projects, Distributed Energy Companies, and Energy Generating Facilities. Generation has several equity investments in energy development projects and energy generating facilities. Generation has evaluated the significant agreements, ownership structures and risks of each of its equity investments, and determined that certain of the entities are

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VIEs because the entity has an insufficient amount of equity at risk to finance its activities, Generation guarantees the debt of the entity, provides equity support, or provides operating services to the entity. Generation has reviewed the entities and has determined that Generation is not the primary beneficiary of the entities that qualify as VIEs because Generation does not have the power to direct the activities that most significantly impact the VIEs economic performance.

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 $85 million and was paid incrementally over an approximate two year period (see Note 24 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 1 Significant Accounting Policies.) 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 another distributed energy company. 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 through the first quarter of 2017 in proportion to their ownership interests, which is up to $172 million for the tax equity investor and up to $78 million for Generation (see Note 24 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. 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.

Both distributed energy companies from the 2015 and 2014 arrangements are considered related parties.

ComEd, PECO and BGE

The financing trust of ComEd, ComEd Financing III, the financing trusts of PECO, PECO Trust III and PECO Trust IV, and the financing trust of BGE, BGE Capital Trust II, are not consolidated in Exelon s, ComEd s, PECO s or BGE s financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd, PECO, and BGE have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, PECO Trust IV or BGE Capital Trust II as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. See Note 14 Debt and Credit Agreements for additional information.

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3. Regulatory Matters (All Registrants)

The following matters below discuss the current status of material regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act (Exelon and ComEd).

Background

Since 2011, ComEd s electric distribution rates are established through a performance-based formula rate, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois electric utility infrastructure.

Participating utilities are required to file an annual update to the performance-based formula rate on or before May 1, with resulting rates effective in January of the following year. This annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred for that year (annual reconciliation). See *Annual Electric Distribution Filings* below for further details. Throughout each year, ComEd records 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 best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. As of December 31, 2016, and December 31, 2015, ComEd had a regulatory asset associated with the electric distribution formula rate of $188 million and $189 million, respectively. The regulatory asset associated with electric distribution formula rate is amortized to Operating revenues in ComEd s Consolidated Statement of Operations and Comprehensive Income as the associated amounts are recovered through rates.

Participating utilities are also required to file an annual update on their AMI implementation progress. On April 1, 2016, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC, which allows for the installation of more than four million smart meters throughout ComEd s service territory through 2018. To date, approximately three million smart meters have been installed in the Chicago area.

Pursuant to EIMA, ComEd annually contributes $4 million for customer education for as long as the AMI Deployment Plan remains in effect. Additionally, ComEd contributed $10 million annually through 2016 to fund customer assistance programs for low-income customers, which are not recoverable through rates.

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

Annual Electric Distribution Filings

For each of the following years, the ICC approved the following total increases/(decreases) in ComEd s electric distributions formula rate filings:

Annual Electric Distribution Filings		**2016**		**2015**		**2014**
ComEd s requested total revenue requirement increase (decrease)	$	138	$	(50)	$	269
Final ICC Order						
Initial revenue requirement increase	$	134	$	85	$	160
Annual reconciliation (decrease) increase		(7)		(152)		72
Total revenue requirement increase (decrease)	$	127[(a)]	$	(67)	$	232
Allowed Return on Rate Base:						
Initial revenue requirement		6.71%		7.05%		7.06%
Annual reconciliation		6.69%		7.02%		7.04%
Allowed ROE:						
Initial revenue requirement		8.64%		9.14%		9.25%
Annual reconciliation		8.59%[(b)]		9.09%[(b)]		9.20%[(b)]
Effective date of rates		January 2017		January 2016		January 2015

(a) On December 20, 2016, the ICC granted ComEd s and other parties joint application for rehearing on the impact that changing ComEd s OSHA recordable rate for 2014 and 2015 has on the revenue requirement approved in this order. ComEd has proposed that the 2016 total electric distribution revenue requirement be reduced by $18 million which would be refunded to customers in 2017.

(b) Includes a reduction of 5 basis points for a reliability performance metric penalty.

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

Background

On December 7, 2016, FEJA was signed into law by the Governor of Illinois. FEJA is effective June 1, 2017, and includes, among other provisions, (1) a ZES providing compensation for certain nuclear-powered generating facilities, (2) an extension of and certain adjustments to ComEd s electric distribution formula rate, (3) new cumulative persisting annual energy efficiency MWh savings goals for ComEd, (4) revisions to the Illinois RPS requirements, (5) provisions for adjustments to or termination of FEJA programs if the average impact on ComEd s customer rates exceeds specified limits, (6) revisions to the existing net metering statute to (i) mandate net metering for community generation projects, and establish billing procedures for subscribers to those projects, (ii) provide immediately for netting at the energy-only rate for nonresidential customers, and (iii) transition from netting at the full retail rate to the energy-only rate for certain residential net metering customers once the net meter customer load equals 5% of total peak demand supplied in the previous year and (7) support for low income rooftop and community solar programs.

Zero Emission Standard

FEJA includes a ZES that provides compensation through the procurement of ZECs targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet specific eligibility criteria. ZES will have a 10-year duration extending through May 31, 2027.

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Eligible generators may participate in a procurement event overseen by the Illinois Power Agency and selected generators will directly contract with Illinois utilities for the procurement of the ZECs based upon the number of MWh produced by the eligible facilities, subject to specified annual caps. The ZEC price will be based upon the current social cost of carbon as determined by the federal government and is initially established at $16.50 per MWh of production, subject to future adjustments based on specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices.

Illinois utilities, including ComEd, will be required to purchase from eligible nuclear facilities an amount of ZECs equivalent to 16% of the actual amount of electricity delivered in 2014. ComEd will recover all costs associated with purchasing ZECs through a new rate rider, which will provide for an annual reconciliation and true-up to actual costs incurred by ComEd to purchase ZECs, with any difference to be credited to or collected from ComEd s retail customers in subsequent periods.

See Note 9 Early Nuclear Plant Retirements for the impacts of the provisions above on Generation s Consolidated Balance Sheets and Consolidated Statements of Operations and Comprehensive Income. The provisions do not impact ComEd s Consolidated Balance Sheets, Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows until 2017.

ComEd Electric Distribution Rates

FEJA extends the sunset date for ComEd s performance-based electric distribution formula rate from 2019 to the end of 2022, allows ComEd to revise the electric distribution formula rate to eliminate the ROE collar, and allows ComEd to implement a decoupling tariff if the electric distribution formula rate is terminated at any time. ComEd will revise its electric distribution formula rate to eliminate the ROE collar, which will eliminate any unfavorable or favorable impacts of weather or load from ComEd s electric distribution formula rate revenues beginning with the reconciliation filed in 2018 for the 2017 calendar year. ComEd will begin reflecting the impacts of this change in its electric distribution services costs regulatory asset or liability beginning in 2017.

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

Energy Efficiency

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

Beginning January 1, 2018, FEJA provides for new cumulative annual energy efficiency MWh savings goals for ComEd, which are designed to achieve 21.5% of cumulative persisting annual MWh savings by 2030, as compared to the deemed baseline of 88 million MWhs of electric power and energy sales. FEJA, deems the cumulative persisting annual MWh savings to be 6.6% from 2012 through the end of 2017. ComEd expects to spend approximately $250 million to $400 million annually from 2017 through 2030 to achieve these energy efficiency MWh savings goals. In addition, FEJA extends the peak demand reduction requirement from 2018 to 2026. Because the new requirements

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apply beginning in 2018, FEJA extends the existing energy efficiency plans, which were due to end on May 31, 2017, through December 31, 2017. FEJA also exempts customers with demands over 10 MW from energy efficiency plans and requirements beginning June 1, 2017.

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

ComEd expects to cancel its existing energy efficiency rider, at which time it must perform a reconciliation of revenues and costs incurred through the cancellation date and issue a one-time credit on retail customers bills for any over-recoveries. As of December 31, 2016, ComEd s over-recoveries associated with its existing energy efficiency rider of $141 million were reflected in Current regulatory liabilities on Exelon s and ComEd s Consolidated Balance Sheets. As a result, ComEd expects to provide credits to customers in 2017 to address this over-recovery.

Renewable Portfolio Standard

Existing Illinois law requires ComEd to purchase each year an increasing percentage of renewable energy resources for the customers for which it supplies electricity. This obligation is satisfied through the procurement of renewable energy credits (RECs). FEJA revises the Illinois RPS to require ComEd to procure RECs for all retail customers by June 2019, regardless of the customers electricity supplier, and provides support for low-income rooftop and community solar programs, which will be funded by the existing Renewable Energy Resources Fund and ongoing RPS collections. ComEd will recover all costs associated with purchasing RECs through rate riders, which will provide for a reconciliation and true-up to actual costs, with any difference between revenues and expenses to be credited to or collected from ComEd s retail customers in subsequent periods. The first reconciliation and true-up for RECs will cover revenues and costs for the four year period beginning June 1, 2017 through May 31, 2021. Subsequently, the RPS rate rider will provide for an annual reconciliation and true-up.

Customer Rate Increase Limitations

FEJA includes provisions intended to limit the average impact on ComEd customer rates for recovery of costs incurred under FEJA as follows: (1) for a typical ComEd residential customer, the average impact must be less than $0.25 cents per month, (2) for nonresidential customers with a peak demand less than 10 MW, the average annual impact must be less than 1.3% of the average amount

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paid per kWh for electric service by Illinois commercial retail customers during 2015, and (3) for nonresidential customers with a peak demand greater than 10 MW, the average annual impact must be less than 1.3% of the average amount paid per kWh for electric service by Illinois industrial retail customers during 2015.

By June 30, 2017, ComEd must submit a 10-year projection to the ICC of customer rate impacts for residential customers and nonresidential customers with a peak demand less than 10 MW. Thereafter, beginning in 2018, ComEd must submit a report to the ICC for residential customers and nonresidential customers with a peak demand less than 10 MW by February 15th and June 30th of each year, respectively. For nonresidential customers with a peak demand greater than 10 MW, ComEd must submit a report to the ICC by May 1 of each year if a rate reduction will be necessary in the following year. For residential customers, the reports will include the actual costs incurred under FEJA during the preceding year and a rolling 10-year customer rate impact projection. The reports for nonresidential customers with a peak demand less than 10 MW will also include the actual costs incurred under FEJA during the preceding year, as well as the average annual rate increase from January 1, 2017 through the end of the preceding year and the average annual rate increase projected for the remainder of the 10-year period.

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

For the energy efficiency formula, ComEd will record a regulatory asset or liability and corresponding increase or decrease to Operating revenues for any differences between the revenue requirement in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. For the other rate riders to be established under FEJA, ComEd will record a regulatory asset or liability for any differences between revenues and incurred expenses. FEJA did not have any impacts on ComEd s Consolidated Statements of Operations and Comprehensive Income or Consolidated Statements of Cash Flows in 2016.

Illinois Procurement Proceedings (Exelon, Generation and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As of December 31, 2016, ComEd has completed all required ICC-approved procurements as called for by the IPA Procurement Plan s timeline.

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Energy Efficiency and Renewable Energy Resources (Exelon and ComEd).

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

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

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 June 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. ComEd executed the sourcing agreement with FutureGen in accordance with the ICC s order. The order also directed 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.

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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. 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

2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO). On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of $190 million to its annual service revenues for electric delivery, which requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On December 17, 2015, the PAPUC approved the settlement of PECO s electric distribution rate case, which included the approval of the In-Program Arrearage Forgiveness (IPAF) Program. The approved electric delivery rates became effective on January 1, 2016.

The IPAF Program provides for forgiveness of a portion of the eligible arrearage balance of its low-income Customer Assistance Program (CAP) accounts receivable at program inception. The forgiveness will be granted to the extent CAP customers remain current over the duration of the five-year payment agreement term. The Settlement guarantees PECO s recovery of two-thirds of the arrearage balance through a combination of customer payments and rate recovery, including through future rates cases if necessary. The remaining one-third of the arrearage balance has been absorbed by PECO through bad debt expense on its Consolidated Statements of Operations. In October 2016, the IPAF was fully implemented. A regulatory asset of $11 million representing previously incurred bad debt expense associated with the eligible accounts receivable balances was recorded as of December 31, 2016.

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

The second DSP Program included a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income CAP customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By an Order entered on January 24, 2014, the PAPUC approved PECO s plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. The PAPUC, 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.

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On December 4, 2014, the PAPUC approved PECO s third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO 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 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design changes the rate structure of PECO s CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO s universal service fund cost. On July 8, 2015, the CAP Design was approved by the PAPUC, and subsequently implemented in October 2016 as planned.

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. On December 8, 2016, the PAPUC approved the fourth DSP Program for a 48-month term and deferred CAP Shopping to another proceeding. OCA and Low Income Advocates subsequently filed a Petition for Reconsideration and Clarification, which is pending before the PAPUC.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, pursuant to Act 129 and the follow-on Implementation Order of 2009, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million electric smart meters and an AMI communication network by 2020. As approved by the PAPUC, PECO accelerated its installation and deployed substantially all smart meters by December 31, 2015, for a total of 1.7 million smart meters. PECO spent $578 million and $155 million on smart meter and smart grid infrastructure, respectively, of which $200 million has been funded by SGIG. Recovery of smart meter costs are reflected in base rates effective January 1, 2016.

Energy Efficiency Programs (Exelon and PECO). The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provided energy consumption reduction requirements for the second phase of Act 129 s EE&C program, which went into effect on June 1, 2013. Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II Plan with the PAPUC on November 1, 2012. The plan set forth how PECO would reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016, adjusted for weather and extraordinary loads. The implementation order permitted PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions had to be through programs directed toward PECO s public

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and low income sectors, respectively. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company s total annual revenue as of December 31, 2006.

On March 15, 2013 and February 28, 2014, PECO filed Petitions for Approval to amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers through May 31, 2014 and May 31, 2016, respectively. PECO proposed to fund the estimated $10 million annual costs of the plan by modifying incentive levels for other Phase II programs. The costs of the DLC program were recovered through PECO s Energy Efficiency Plan surcharge along with other Phase II Plan costs. The PAPUC granted PECO s Petitions on May 5, 2013 and April 23, 2014, respectively. On November 15 2016, PECO reported to the PAPUC that as of the conclusion of the EE&C Phase II Plan, all plan requirements have been met. A final Phase II compliance determination is expected to be issued in the first half of 2017.

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.

Alternative Energy Portfolio Standards (Exelon and PECO). In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO s rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8%, and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO continues to procure alternative energy credits through full requirements contracts and its existing long-term solar contracts to meet the annual AEPS compliance requirements. All AEPS compliance costs are being recovered on a full and current basis from default service customers through the GSA.

Pennsylvania Retail Electricity and Gas Markets (Exelon and PECO). Beginning in 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania s retail electricity market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. Through various orders, the PAPUC issued default electric service pricing for customers in PECO s service territory. See Pennsylvania procurement proceedings discussed above for additional details.

In early 2014, the extreme weather in PECO s service territory resulted in increased electricity commodity costs causing certain shopping customers to receive unexpectedly high utility bills. In response to a significant number of customer complaints throughout Pennsylvania, on April 3, 2014,

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the PAPUC unanimously voted to adopt two rulemaking orders to address the issue. The first rulemaking order requires electric generation suppliers to provide more consumer education regarding their contract. The second rulemaking order requires electric distribution companies to enable customers to switch suppliers within three business days (known as accelerated switching). The improved customer education and accelerated switching were to be in place within 30 days and six months of approval of the orders, respectively. The orders became final on June 14, 2014. On December 4, 2014, the PAPUC approved PECO s implementation plan (known as Bill on Supplier Switch), allowing PECO to implement accelerated switching by the December 15, 2014 deadline.

On September 12, 2013, the PAPUC issued an Order that initiated an investigation into Pennsylvania s natural gas retail market, including the role of the existing default service model and opportunities for market enhancements. On December 18, 2014, the PAPUC issued a Final Order directing the Office of Competitive Market Oversight (OCMO) to continue its investigation, confirming that natural gas distribution companies should remain with the default service model for the time being and directing establishment of a working group to examine other competitive issues. The OCMO has established a working group to review operation of the natural gas retail market and to consider potential recommendations on competitive issues.

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

On May 7, 2015, the PAPUC approved PECO s modified natural gas LTIIP. In accordance with the approved LTIIP, PECO plans to spend $534 million through 2022 to further accelerate the replacement of existing gas mains and to relocate meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas LTIIP expenditures. On September 11, 2015, the PAPUC entered its Opinion and Order approving PECO s petition for a gas DSIC.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIP. In accordance with the LTIIP (System 2020 plan), PECO plans to spend $275 million over the next five years to modernize and storm-harden its electric distribution system, making it more weather resistant and less vulnerable to damage. The DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases. On October 22, 2015, the PAPUC entered its Opinion and Order approving PECO s proposed petition for its electric LTIIP and DSIC.

Maryland Regulatory Matters

2016 Maryland Electric Distribution Base Rates (Exelon, PHI and Pepco). On November 15, 2016, the MDPSC approved an increase in electric distribution base rates of $53 million based on a ROE of 9.55%. The new rates became effective for services rendered on or after November 15, 2016. MDPSC also approved Pepco s recovery of substantially all of its capital investment and regulatory assets associated with its AMI program as part of the newly effective rates as well as a recovery over a five-year period of transition costs related to a new billing system implemented in 2015. As a result,

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during the fourth quarter of 2016, Exelon, PHI and Pepco established a regulatory asset of $13 million, wrote-off $3 million in disallowed AMI costs and recorded a pre-tax credit to net income for $10 million. Additionally, the MDPSC denied Pepco s request to extend its Grid Resiliency Program surcharge for new system reliability and safety improvement projects, with costs for such programs to be recovered going forward through base rates.

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, which was later modified to 10 years, 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 Base Rates (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

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MDPSC s order but with the Circuit Court for Baltimore City. On November 15, 2016, Baltimore County Circuit Court issued an order deciding that the cases should be consolidated and should proceed in Baltimore County Circuit Court. However, on January 9, 2017, BGE filed to withdraw its appeal of the MDPSC s orders and on January 10, 2017, the residential consumer advocate filed to withdraw its appeal as well. 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.

Cash Working Capital Order (Exelon and BGE). On November 17, 2016, the MDPSC rendered a decision in the proceeding to review BGE s request to recover its cash working capital (CWC) requirement for its Provider of Last Resort service, also known as Standard Offer Service (SOS), as well as other components that make up the Administrative Charge, the mechanism that enables BGE to recover all of its SOS-related costs. The Administrative Charge is now comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which is an adder to the utility s SOS rate to act as a proxy for retail suppliers costs. The Commission accepted BGE positions on recovery of CWC and pass-through recovery of BGE s actual uncollectibles and incremental costs. The order also grants BGE a modest return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE s next rate case. On December 16, 2016, MDPSC Staff requested clarification concerning the amount of return on the SOS awarded to BGE and on December 19, 2016, the residential consumer advocate sought rehearing of the return awarded. On January 24, 2017, the MDPSC issued an order denying the MDPSC Staff request for clarification and the residential consumer advocate request for rehearing.

2014 Maryland Electric and Gas Distribution Base Rates (Exelon and BGE). On July 2, 2014, and as amended on September 15, 2014, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of $99 million and $68 million, respectively.

On October 17, 2014, BGE filed with the MDPSC a unanimous settlement agreement (the Settlement Agreement) reached with all parties to the case under which it would receive an increase of $22 million in electric base rates and an increase of $38 million in gas base rates. The Settlement Agreement establishes new depreciation rates which have the effect of decreasing annual depreciation expense by approximately $20 million, primarily for electric. On December 4, 2014, the Public Utility Law Judge issued a proposed order approving the Settlement Agreement without modification, which became a final order on December 12, 2014. The approved distribution rate order authorizing BGE to increase electric and gas distribution rates became effective for services rendered on or after December 15, 2014.

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. Refer to AMI programs in the Regulatory Assets and Liabilities section below for further details.

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

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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. The residential consumer advocate 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. On November 15, 2016, Baltimore County Circuit Court issued an order deciding that the cases should be consolidated and should proceed in Baltimore County Circuit Court. However, on January 9, 2017, BGE filed to withdraw its appeal of the MDPSC s orders and on January 10, 2017, the residential consumer advocate filed to withdraw its appeal as well.

As a combined result of the MDPSC orders, BGE recorded a $52 million charge to Operating and maintenance expense in Exelon s and BGE s Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets. Pursuant to the combined MDPSC orders, BGE also reclassified $54 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 December 31, 2016.

2013 Maryland Electric and Gas Distribution Base Rates (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 December 31, 2016, BGE has received approval of its updated surcharge filings three times for rates to be effective in 2014, 2015 and 2016.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE s 2013 electric and 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 30, 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

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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.

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.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 requiring BGE and other Maryland utilities to file several comprehensive reports with short-term and long-term plans to improve reliability and grid resiliency that were due at various times before August 30, 2013.

On September 3, 2013, BGE filed a comprehensive long term assessment examining potential alternatives for improving the resiliency of the electric grid and a staffing analysis reviewing historical staffing levels as well as forecasting staffing levels necessary under various storm scenarios. During the summer of 2014, an evaluation of the reports filed by BGE and other Maryland utilities was undertaken by consultants on behalf of the MDPSC and MDPSC Staff. The MDPSC Staff also proposed standards for reliability during major events and estimated times of restoration as well as undertaking an evaluation of performance-based ratemaking principles and methodologies that would more directly and transparently align reliable service with the utilities distribution rates and that reduce returns or otherwise penalize sub-standard performance. The MDPSC held hearings in September 2014. BGE currently cannot predict the outcome of these proceedings, which may result in increased capital expenditures and operating costs.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation intended to accelerate gas infrastructure replacements in Maryland was signed into law. The law established a mechanism, separate from base rate proceedings, for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects incurred after June 1, 2013. The monthly surcharge and infrastructure replacement costs must be approved by the MDPSC and are subject to a cap and require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in

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a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE s plan and surcharge. On July 1, 2016, BGE filed an amendment to its infrastructure replacement plan, which the MDPSC conditionally approved in an order dated November 23, 2016. The revised surcharge reflecting the costs of the amendment became effective January 1, 2017. On December 2, 2016, BGE filed a surcharge update to be effective February 1, 2017, including a true-up of cost estimates included in the 2016 surcharge, along with its 2017 project list and projected capital estimates of $131 million to be included in the 2017 surcharge calculation. The MDPSC subsequently approved BGE s 2017 project list and the proposed surcharge for 2017, which included the 2016 surcharge true-up. As of December 31, 2016, BGE recorded a regulatory liability of $2 million, representing the difference between the surcharge revenues and program costs.

In 2014, the residential consumer advocate in Maryland appealed MDPSC s decision on BGE s infrastructure replacement plan and associated surcharge with the Baltimore City Circuit Court, who affirmed the MDPSC s decision. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. During the third quarter of 2015, the residential consumer advocate, MDPSC and BGE filed briefs. Oral argument in this matter was held before the Court of Special Appeals on November 3, 2015. On January 28, 2016, the Maryland Court of Special Appeals issued a decision affirming the MDPSC s decision. As the residential consumer advocate did not appeal the decision of the Court of Special Appeals, the matter is now closed.

Delaware Regulatory Matters

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

2016 Delaware 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 each of the rate increases two months after filing the applications which were effective July 16, 2016. On December 1, 2016, the DPSC approved that an additional $30 million in electric distribution base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order, and an additional $10 million in gas base rates be implemented effective December 17, 2016, subject to refund based on the final DPSC order.

2013 Delaware Electric Distribution Base Rates (Exelon, PHI and DPL). In March 2013, and as amended on September 20, 2013, DPL filed for an electric distribution base rate increase with the DPSC, ultimately requesting an annual increase of $39 million.

In August 2014, the DPSC issued a final order in DPL s 2013 electric distribution rate case for an annual increase of $15 million and an ROE of 9.7%. Rates became effective on May 1, 2014.

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In September 2014, DPL filed an appeal with the Delaware Superior Court of the DPSC s August 2014 order in this proceeding, seeking the court s review of the DPSC s decision relating to the recovery of costs associated with one component of employee compensation, certain retirement benefits and credit facility expenses. The Division of the Public Advocate filed a cross-appeal in September 2014, pertaining to the treatment of a prepaid pension expense and other postretirement benefit obligations in base rates. Under the Settlement Agreement related to the Merger, the parties agreed to suspend the appeal and, upon consummation of the Merger, to the withdrawal of the appeal and the cross-appeal with prejudice. In accordance with the settlement, on April 13, 2016, the parties filed a Stipulation of Dismissal with the court to dismiss the appeal and the cross-appeal, at which time the matter was closed.

District of Columbia Regulatory Matters

2016 District of Columbia 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, and further updated to approximately $77 million on February 1, 2017, 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 November 22, 2016, following Pepco s October 7, 2016 request for reconsideration of the order, the DCPSC issued an order stating that its September 9, 2016 order was not final and confirming that issues related to the BSA, including potential remedial actions, would be addressed in Pepco s rate case. 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.

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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, and the DCPSC granted this request by order dated October 27, 2016.

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 New Jersey 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 non-utility generators and (ii) costs related to surcharges for the New Jersey Societal Benefit Program (a statewide public interest program that is intended to benefit low income customers and address other public policy goals) and ACE s uncollectible accounts.

As filed, the net impact of adjusting the charges as proposed would have been an overall annual rate 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.

On November 30, 2016, the NJBPU approved a stipulation of settlement entered into by the parties providing for an overall annual rate increase of $1 million effective January 1, 2017. This settlement included a credit of approximately $10 million to the Non-Utility Generation charge deferral balance and a credit of approximately $7 million to the Uncollectible deferral balance. These credits were directed to be applied to the deferral balances in an NJBPU order dated October 31, 2016. That order approved the Joint Recommendation for Settlement of the Most Favored Nation Provision, which was a condition of the merger between Exelon Corporation and Pepco Holdings, Inc. This rate increase will have no effect on ACE s operating income, since these revenues provide for recovery of deferred costs under an approved deferral mechanism.

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On February 1, 2017, ACE submitted its 2017 annual petition with the NJBPU seeking to reconcile and update the same categories of charges and costs as set forth in its 2016 annual petition discussed above. The net impact of adjusting the charges as proposed is an overall annual rate decrease of approximately $29 million, including New Jersey Sales and Use Tax. The matter is pending at the NJBPU and will be updated for January through March 2017 actual data. ACE has requested that the NJBPU place the new rates into effect by June 1, 2017. There is no assurance that NJBPU will put final rates in effect by the requested date.

New York Regulatory Matters

New York Clean Energy Standard (Exelon, Generation). On August 1, 2016, the New York Public Service Commission (NYPSC) issued an order establishing the CES, a component of a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that meet the criteria demonstrating public necessity as determined by the NYPSC. The New York State Energy Research and Development Authority (NYSERDA) will centrally procure the ZECs from eligible plants through a 12-year contract, to be administered in six two-year tranches, extending from April 1, 2017 through March 31, 2029. ZEC payments will be made to the eligible resources based upon the number of MWh produced, subject to specified caps and minimum performance requirements. The price to be paid for the ZECs under each tranche will be administratively determined using a formula based on the social cost of carbon as determined in 2016 by the federal government, subject to pricing adjustments designed to lower the ZEC price based on increase in underlying energy and capacity prices. The ZEC price for the first tranche has been set at $17.48 per MWh of production. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) shall be required to purchase an amount of ZECs equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers shall be incorporated into the commodity charges on customer bills.

The NYPSC initially identified the three plants eligible for the ZEC program to include, for now, the FitzPatrick, Ginna, and Nine Mile Point nuclear facilities. As issued, the order also provided that the duration of the program beyond the first tranche was conditional upon a buyer purchasing the FitzPatrick facility and taking title prior to September 1, 2018. On November 18, 2016, the required contracts with NYSERDA were executed for Ginna and Nine Mile Point, in addition to Entergy s execution of the required contract for the FitzPatrick facility.

Several parties filed with the NYPSC requests for rehearing or reconsideration of the CES. Generation and CENG also filed a request for clarification, or in the alternative limited rehearing, that the condition limiting the duration of the program beyond the first tranche be limited to the eligibility of the FitzPatrick plant only and have no bearing on Ginna or Nine Mile Point s eligibility for the full 12-year duration. On December 15, 2016, the NYPSC approved Exelon s petition to clarify this condition and denied all petitions for rehearing of the CES. Parties have until mid-April to appeal to New York State court the denials of the requests for rehearing. In addition, one Petition seeking to invalidate the ZEC program was filed in New York State court on November 30, 2016, and amended on January 13, 2017, arguing that the NYPSC violated certain technical provisions of the State Administrative Procedures Act (SAPA) when adopting the ZEC program.

On 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

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and that it discriminates against out of state competitors. On December 9, 2016, Generation and CENG filed a motion to intervene in the case and to dismiss the lawsuit. The motion to intervene has been granted and the motion to dismiss is pending.

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 9 Early Nuclear Plant Retirements for additional information relative to Ginna and Nine Mile Point, and 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 of operations 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 did not plan to retire shortly after the expiration of the RSSA, Ginna was required to file a notice to that effect with the NYPSC no later than September 30, 2016. Under the terms of the RSSA, if Ginna continues to operate after June 14, 2017, Ginna would be required to make certain refund payments up to a maximum of $20 million to RG&E related to capital expenditures. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the CES. As stated previously, on November 18, 2016 the required contract with NYSERDA was executed by Generation and CENG for Ginna. Subject to prevailing over any administrative or legal challenges, it is expected the CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 9 Early Nuclear Plant Retirements for additional discussion of Ginna.

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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. On December 13, 2016, BGE filed with the FERC to modify its FERC-approved formula to recover its existing regulatory asset and any future changes to its regulatory asset concerning various tax issues including certain deferred income taxes.

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

Annual Transmission Filings	ComEd			BGE		
	2016	2015	2014	2016	2015	2014
Initial revenue requirement increase	$ 90	$ 68	$ 36	$ 12	$	$ 9
Annual reconciliation increase (decrease)	4	18	(14)	3	(3)	5
Dedicated facilities increase [(a)]				13	13	3
Total revenue requirement increase	$ 94	$ 86	$ 22	$ 28	$ 10	$ 17
Allowed return on rate base [(c)]	8.47%	8.61%	8.62%	8.09%	8.46%	8.53%
Allowed ROE [(d)]	11.50%	11.50%	11.50%	10.50%	11.30%	11.30%
	June 2016	June 2015	June 2014	June 2016	June 2015	June 2014

Effective date of rates

smission	Pepco 2016	Pepco 2015	Pepco 2014	DPL 2016	DPL 2015	DPL 2014	ACE 2016	ACE 2015
ease)	$ 2	$ 10	$ (9)	$ 8	$ 15	$ 4	$ 8	$ 10
iliation ease	(10)	(3)	(1)	(10)	(1)	6	(14)	2
nment ease)	(15)	(2)	17	(12)	(2)	15		
ecrease)	$ (23)	$ 5	$ 7	$ (14)	$ 12	$ 25	$ (6)	$ 12
n on rate	7.88%	8.36%	8.60%	7.21%	7.80%	8.05%	7.83%	8.51%
d)	10.50%	11.30%	11.30%	10.50%	11.30%	11.30%	10.50%	11.30%
of	June 2016	June 2015	June 2014	June 2016	June 2015	June 2014	June 2016	June 2015

(a) 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.

(b) 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.

(c) Represents to the weighted average debt and equity return on transmission rate bases.

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(d) As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.5%, inclusive of a 50 basis point incentive adder for being a member of a regional transmission organization.
(e) The time period for any challenges to the annual transmission formula rate update flings expired with no challenges submitted.

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

In August 2009, the court issued its decision affirming the FERC s order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. On June 15, 2016, a number of parties, including Exelon and the Utility Registrants filed an Offer of Settlement with FERC. Each state that is a party in this proceeding either signed, or will not oppose, the settlement. 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.

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The Utility Registrants are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. The Utility Registrants will work with PJM to continue to evaluate the scope and timing of any required construction projects. The Utility Registrant s estimated commitments are as follows:

	Total	2017	2018	2019	2020	2021
ComEd	$ 97	$ 64	$ 28	$ 5	$	$
PECO	34	14	10	7	2	1
BGE	226	113	55	44	14	
Pepco	104	6	39	40	19	
DPL	63	47	16			
ACE	93	36	39	18		

Complaints at FERC Seeking to Mitigate Illinois and New York Programs Providing ZECs (Exelon and Generation). PJM and NYISO capacity markets include a Minimum Offer Price Rule (MOPR) that is intended to preclude buyers from exercising buyer market power. If a resource is subjected to a MOPR, its offer is adjusted to remove the revenues it receives through a federal, state or other government-provided financial support program, resulting in a higher offer that may not clear the capacity market. Currently, the MOPRs in PJM and NYISO apply only to certain new resources. Exelon has generally opposed policies that require subsidies or give preferential treatment to generation providers or technologies that do not provide superior reliability or environmental benefits, or that would threaten the reliability and value of the integrated electricity grid. Thus, Exelon has supported a MOPR as a means of minimizing the detrimental impact certain subsidized resources could have on capacity markets (such as the New Jersey (LCAPP) and Maryland (CfD) programs). However, in Exelon s view, MOPRs should not be applied to resources that receive compensation for providing superior reliability or environmental benefits.

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

Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE). On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 (D.C. Circuit Decision).

Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was

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cost-effective. On January 25, 2016, the U.S. Supreme Court reversed the D.C. Circuit Court decision and remanded the matter to the D.C. Circuit Court. While Exelon cannot predict exactly how the D.C. Circuit Court will handle the matter on remand, Exelon does not expect there will be any significant change in how demand response resources have or will participate in and be paid by wholesale energy markets. Thus, Exelon does not anticipate that there will be any impact to the Registrants results of operations or cash flows based on these proceedings.

New England Capacity Market Results (Exelon and Generation). On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 31, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE s February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE s filings became effective by operation of law pursuant to a notice issued by the secretary of FERC on September 16, 2014. Several parties sought rehearing of the secretary s notice which was effectively denied in October 2014 and have since appealed the matter to the D.C. Circuit Court. On October 25, 2016, the D.C. Circuit Court dismissed the appeal.

Operating License Renewals (Exelon and Generation). Generation has 40-year operating license 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.

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 units 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 December 31, 2016, $28 million of direct costs associated with

Conowingo licensing efforts have been capitalized-to-date.

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

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

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

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The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE as of December 31, 2016 and December 31, 2015:

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

Less: current portion	1,342	190	29	208	653	162	59	96
Total noncurrent regulatory assets	$ 10,046	$ 977	$ 1,681	$ 504	$ 2,851	$ 690	$ 289	$ 405

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					Successor			
December 31, 2016	**Exelon**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Regulatory liabilities								
Other postretirement benefits	$ 47	$	$	$	$	$	$	$
Nuclear decommissioning	2,607	2,169	438					
Removal costs	1,601	1,324		141	136	18	118	
Deferred rent	39				39			
Energy efficiency and demand response programs	185	141	41		3	3		
DLC program costs	8		8					
Electric distribution tax repairs	76		76					
Gas distribution tax repairs	20		20					
Energy and transmission programs	134	60	56		18	8	5	5
Other	72	4	5	19	41	2	17	20
Total regulatory liabilities	4,789	3,698	644	160	237	31	140	25
Less: current portion	602	329	127	50	79	11	43	25
Total noncurrent regulatory liabilities	$ 4,187	$ 3,369	$ 517	$ 110	$ 158	$ 20	$ 97	$

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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	1,616	64	1,473	79	214	137	36	41
AMI programs	399	140	63	196	267	180	87	
Under-recovered distribution service costs	189	189						
Debt costs	47	46	1	8	36	19	10	7
Fair value of long-term debt	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	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	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 noncurrent regulatory assets	$ 6,065	$ 895	$ 1,583	$ 514	$ 2,277	$ 661	$ 299	$ 414

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					Predecessor			
December 31, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**	**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	131	53	60	18	27	16	19	8
Over-recovered revenue decoupling	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 noncurrent regulatory liabilities	$ 4,201	$ 3,459	$ 527	$ 184	$ 147	$ 29	$ 111	$ 7

Pension and other postretirement benefits. As of December 31, 2016, Exelon had regulatory assets of $3,075 and regulatory liabilities of $47 million related to ComEd s and BGE s portion of deferred costs associated with Exelon s pension plans and ComEd s, PECO s and BGE s portion of deferred costs associated with Exelon s other postretirement benefit plans. PECO s pension regulatory recovery is based on cash contributions and is not included in the regulatory asset (liability) balances. The regulatory asset (liability) is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses (gains) attributable to Exelon s pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the Constellation merger related to BGE s portion of the deferred costs associated with legacy Constellation s pension and other postretirement benefit plans. The BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the Constellation merger. As of December 31, 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 and recovered 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. See Note 17 Retirement Benefits for additional detail. No return is earned on Exelon s regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with accelerated depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income

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tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC s March 2011 rate order. For PECO, this amount includes the impacts of electric and gas distribution repairs in the deductibility pursuant to PUC s 2010 and 2015 rate case settlement agreements. As of December 31, 2016, includes transmission-related regulatory assets that require FERC approval separate from the transmission formula rate of $22 million, $38 million, $31 million, $20 million and $19 million for ComEd, BGE, Pepco, DPL and ACE, respectively. 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, $26 million, $18 million and $15 million for ComEd, BGE, Pepco, DPL and ACE, respectively. See Note 15 Income Taxes, Note 17 Retirement Benefits, and the Transmission Formula Rate section above for additional information. ComEd, PECO, BGE, Pepco, DPL and ACE are not earning a return on the regulatory asset in rates. The recovery period is over the life of the associated assets.

AMI programs. For ComEd, this amount represents meter costs associated with ComEd s AMI pilot program approved in ComEd s 2010 rate case. The recovery periods for these meter costs are through January 2020. As of December 31, 2016 and December 31, 2015, ComEd had regulatory assets of $162 million and $137 million, respectively, related to accelerated depreciation costs resulting from the early retirements of non-AMI meters, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the regulatory asset. For PECO, this amount primarily represents accelerated depreciation on PECO s non-AMI meter assets over a 10-year period ending December 31, 2020. Recovery of smart meter costs are reflected in base rates effective January 1, 2016. For BGE, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters. The incremental costs associated with the installation, along with depreciation, amortization, and an appropriate return, had been building in a regulatory asset since the MDPSC approved the comprehensive smart grid initiative for BGE in August 2010 through approval of the program in BGE s rate order issued June, 2016. As of December 31, 2016, the balance of BGE s regulatory asset was $230 million, which consists of three major components, including $144 million of unamortized incremental deployment costs of the AMI program, $54 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 when approval became effective June 2016. The incremental deployment costs for the AMI program and the non-AMI meter components of the regulatory asset are being amortized and recovered through rates over a 10-year period, which began in June, 2016. A return on the $144 million incremental deployment costs for the AMI program portion of the regulatory asset is included in rates. The $54 million portion of the regulatory asset related to the unamortized cost of the retired non-AMI meters is not earning a return in rates. The $32 million portion related to post-test year incremental program deployment costs have not yet been approved for recovery by the MDPSC and are not currently earning a return for financial reporting purposes. For PHI, this amount represents AMI costs associated with the installation of smart meters and the early retirement of legacy meters throughout the service territories for Pepco and DPL. An AMI program has not been approved by the NJBPU for ACE in New Jersey. Pepco has received approval for recovery of deferred AMI program costs from the DCPSC and the MDPSC in its DC and Maryland service territories. Pepco does earn a return on the AMI deployment costs, but not on the early retirement of legacy meters. DPL has received approval for recovery of deferred AMI program costs from the DPSC in its Delaware service territory and has received a proposed order from the MDPSC approving recovery of deferred AMI program costs in its Maryland service territory. As of December 31, 2016, the DPL deferred AMI program costs pending finalization of the proposed order from the MDPSC are $41 million, of which $14 million relates to retired legacy meters which are not earning a return.

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Under-recovered distribution services costs. These amounts represent under recoveries related to electric distribution services costs recoverable through EIMA s performance based formula rate. Under (over) recoveries for the annual reconciliations are recoverable (refundable) over a one-year period and costs for certain one-time events, such as large storms, are recoverable over a five-year period. ComEd earns and pays a return on under and over-recovered costs, respectively. As of December 31, 2016, the regulatory asset was comprised of $134 million for the 2015 to 2016 annual reconciliations and $54 million related to significant one-time events, including $20 million in deferred storm costs and $11 million of Constellation and PHI merger and integration related costs, and $23 million of smart meter related costs. ComEd s 2015 annual reconciliation regulatory asset includes a reduction of $8 million related to a ComEd-proposed refund to customers for the impact of changing its OSHA recordable rate for 2014 and 2015. As of December 31, 2015, the regulatory asset was comprised of $142 million for the 2014 and 2015 annual reconciliations and $47 million related to significant one-time events, including $36 million in deferred storm costs and $11 million of Constellation merger and integration related costs.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd s, PECO s, BGE s, Pepco s, DPL s and ACE s recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on these costs. Recovery of these costs will continue through 2038 for ComEd and BGE. PECO, Pepco, DPL and ACE are earning a return on the premium of the cost of the reacquired debt through base rates. The regulatory asset for Pepco, DPL and ACE was eliminated at Exelon and PHI as part of acquisition accounting.

Fair value of long-term debt. These amounts represent the unamortized regulatory assets recorded at Exelon for the difference between the carrying value and fair value of the long-term debt of BGE as of the Constellation merger date based on the MDPSC practice to allow BGE to recover its debt costs through rates 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. Exelon is amortizing the regulatory asset and the associated fair value over the life of the underlying debt and is not earning a return on the recovery of these costs.

Fair value of PHI s unamortized energy contracts. These amounts represent 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.

Severance. For BGE, these costs represent deferred severance costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC s March 2011 rate order. Additionally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC s orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

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Asset retirement obligations. These costs represent future legally required removal costs associated with existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd and BGE will recover these costs through future depreciation rates and will earn a return on these costs once the removal activities have been performed. The recovery period will be over the expected life of the related assets. See Note 16 Asset Retirement Obligations for additional information.

MGP remediation costs. ComEd is allowed recovery of these costs under ICC approved rates. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. The period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures, currently estimated to be completed in 2022 for both ComEd and PECO. ComEd and PECO are not earning a return on the recovery of these costs. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. BGE is earning a return on this regulatory asset and these costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. The recovery period for the 10-year period that began January 2006 was extended for an additional 24 months, in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case order. See Note 24 Commitments and Contingencies for additional information.

Under recovered uncollectible accounts. These amounts represent the difference between ComEd s annual uncollectible accounts expense and revenues collected in rates through an ICC-approved rider. The difference between net uncollectible account charge-offs and revenues collected through the rider each calendar year is recovered or refunded over a twelve-month period beginning in June of the following calendar year. ComEd does not earn a return on these under recoveries.

Renewable energy. In December 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 through 2032 in order to meet a portion of its obligations under the Illinois RPS. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). Recovery of these costs will continue through 2032. The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd s cost to purchase energy at the market price and the contracted price.

Energy and transmission programs. These amounts represent under (over) recoveries related to energy and transmission costs recoverable (refundable) under ComEd s ICC and/or FERC-approved rates. Under (over) recoveries are recoverable (refundable) over a one-year period or less. ComEd earns a return or interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2016, ComEd s regulatory asset of $23 million included $15 million associated with transmission costs recoverable through its FERC approved formula rate and $8 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2016, ComEd s regulatory liability of $60 million included $30 million related to over-recovered energy costs and $30 million associated with revenues received for renewable energy requirements. As of December 31, 2015, ComEd s regulatory asset of $43 million included $5 million

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related to under-recovered energy costs, $31 million associated with transmission costs recoverable through its FERC-approved formula rate tariff, 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. See *Transmission Formula Rate* above for further details.

The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO s GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. In addition, the DSP Program costs are presented on a net basis with PECO s GSA under (over)-recovered energy costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO s PAPUC-approved DSP programs for the procurement of electric supply. The filings and procurements of these DSP Programs are recoverable through the GSA over each respective term. DSP II and DSP III each have a 24-month term that began June 1, 2013 and June 1, 2015, respectively. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs. Certain costs included in PECO s original DSP program related to information technology improvements were recovered over a 5-year period that began January 1, 2011. PECO earns a return on the recovery of information technology costs. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2016, PECO s regulatory liability of $56 million included $34 million related to over-recovered costs under the DSP program, $10 million related to over-recovered non-bypassable transmission service charges, $8 million related to the over-recovered natural gas costs under the PGC and $4 million related to over-recovered electric transmission costs. As of December 31, 2015, PECO s regulatory asset of $1 million related to under-recovered non-bypassable transmission service charges. As of December 31, 2015, PECO s regulatory liability of $60 million included $35 million related to 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.

The BGE energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under BGE s market-based SOS program, MBR program, and FERC approved transmission rates, respectively. BGE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. BGE does not earn or pay interest to customers on under-recovered or over-recovered SOS and MBR costs. The recovery or refund period is a twelve-month period beginning in June of the following calendar year. As of December 31, 2016, BGE s regulatory asset of $38 million included $4 million of costs associated with transmission costs recoverable through its FERC approved formula rate, $28 million related to under-recovered electric energy costs, $3 million of abandonment costs to be recovered upon FERC approval, and $3 million 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.

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The Pepco energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under Pepco s market-based SOS program and FERC approved transmission rates. Pepco earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. Pepco does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2016, Pepco s regulatory asset of $6 million related to under-recovered electric energy costs. As of December 31, 2016, Pepco s regulatory liability of $8 million included $5 million of over-recovered transmission costs and $3 million of over-recovered electric energy costs. 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.

The DPL energy costs represent the electric supply, gas supply, and transmission related costs recoverable (refundable) from (to) customers under DPL s market-based SOS program, GCR and FERC approved transmission rates. DPL earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. In Delaware, DPL earns interest on under-recovered costs and pays interest to customers on over-recovered SOS an GCR costs. In Maryland, DPL does not earn or pay interest to customers on under- or over-recovered SOS costs. The asset is being amortized and recovered over the life of the associated assets. As of December 31, 2016, DPL s regulatory asset of $5 million included $1 million of transmission costs recoverable through its FERC approved formula rate and $4 million of under-recovered electric energy costs. As of December 31, 2016, DPL s regulatory liability of $5 million included $2 million of over-recovered electric energy costs and $3 million of over-recovered transmission costs. 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.

The ACE energy costs represent the electric supply and transmission related costs recoverable (refundable) from (to) customers under ACE s market-based BGS program and FERC approved transmission rates. ACE earns or pays interest to customers on under-recovered or over-recovered FERC transmission formula-related costs. ACE earns interest on under-recovered and pays interest to customers on over-recovered BGS costs. As of December 31, 2016, ACE s regulatory asset of $17 million included $6 million of transmission costs recoverable through its FERC approved formula rate and $11 million of under-recovered electric energy costs. As of December 31, 2016, ACE s regulatory liability of $5 million included $4 million of over-recovered transmission costs and $1 million of over-recovered electric energy costs. 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.

Deferred storm costs. In the MDPSC s March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. BGE earns a return on this regulatory asset and the original recovery period of five years was extended for an additional 25 months, in accordance with the MDPSC 2014 electric and natural gas distribution rate case order.

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For Pepco, DPL and ACE, amounts represent total incremental storm restoration costs incurred for repair work due to major storm events in 2016, 2015, 2012 and 2011, including the January 2016 winter storm Jonas for Pepco, June 2015 storm (for DPL and ACE), Hurricane Sandy, the June 2012 derecho, Hurricane Irene and the 2011 severe winter storm (for Pepco), that are recoverable from customers in the Maryland and New Jersey jurisdictions. Pepco s and DPL s costs related to Hurricane Sandy, the June 2012 derecho, Hurricane Irene and Pepco s costs related to the 2011 severe winter storm are being amortized and recovered from customers, each over a five-year period. However, in the November 2016 Pepco Maryland Case No. 9418 order, the Commission ruled that the remaining amortization for the Pepco Maryland February 2010 storm, the January 2011 storm and Hurricane Irene be extended for an additional three years. The reason for the extension was that since these assets would be fully amortized in 2017, Pepco would over-recover these costs if the rates in this case remained in effect beyond July 2017. The January 2017 PULJ report for DPL Maryland Case No. 9424 also recommended that amortization period for Hurricane Irene (DPL MD) be extended an additional three years as well. ACE s costs related to Hurricane Sandy, the June 2012 derecho and Hurricane Irene are being amortized and recovered from customers, each over a three-year period. PHI does not earn a return on these ACE regulatory assets.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. The portion of this regulatory asset that does not earn a regulated rate of return was $9 million as of December 31, 2016, and $19 million as of December 31, 2015. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006 to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007 to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2016 and 2015, BGE recovered $81 million and $73 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. For ComEd, these amounts represent over recoveries related to ComEd s ICC-approved Energy Efficiency and Demand Response Plan. ComEd expects to refund these over recoveries in 2017. ComEd earns a return on the capital investment incurred under the program, but does not earn or pay a return or interest on under or over recoveries, respectively. For PECO, these amounts represent over recoveries of program costs related to both Phase II and Phase III of its PAPUC-approved EE&C Plan. PECO began recovering the costs of its Phase II and Phase III EE&C Plans through a surcharge in June 2013 and June 2016, respectively,

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based on projected spending under the programs. Phase II of the program began on June 1, 2013 and expired on May 31, 2016. Phase III of the program began on June 1, 2016 and will expire on May 31, 2021. PECO does not earn (pay) interest on under (over) collections. For BGE, these amounts represent under (over) recoveries related to BGE s Smart Energy Savers Program®, which includes both MDPSC-approved demand response and energy efficiency programs. For the BGE Peak Rewards℠ demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Also included in the demand response program are customer bill credits related to BGE s Smart Energy Rewards program which began in July 2013 and are being recovered through the surcharge. Actual costs incurred in the energy efficiency program are being amortized over a 5-year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

For Pepco, DPL and ACE, amounts represent recoverable costs associated with customer direct load control and energy efficiency and conservation programs in all jurisdictions that are being recovered from customers. These programs are designed to reduce customers energy consumption. PHI earns a return on these regulatory assets.

Merger integration costs. These amounts include integration costs to achieve distribution synergies related to the Constellation merger transaction. As a result of the MDPSC s February 2013 rate order, BGE deferred $8 million related to non-severance merger integration costs incurred during 2012 and the first quarter of 2013. Of these costs, $4 million was authorized to be amortized over a 5-year period that began in March 2013. The recovery of the remaining $4 million was deferred. In the MDPSC s December 2013 rate order, BGE was authorized to recover the remaining $4 million and an additional $4 million of non-severance merger integration costs incurred during 2013. These costs are being amortized over a 5-year period that began in December 2013. BGE is earning a return on this regulatory asset included in base rates.

These amounts also include integration costs to achieve distribution synergies related to the PHI acquisition. As of December 31, 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. As of December 31, 2016, PHI s regulatory asset of $15 million represents previously incurred PHI acquisition costs expected to earn a return and be recovered in distribution rates in the Maryland service territories of Pepco and DPL.

Under (Over)-recovered electric and gas revenue decoupling. For BGE, these amounts represent the electric and gas distribution costs recoverable from or (refundable) to customers under BGE s decoupling mechanisms, which does not earn a rate of return and is being recovered over the life of the associated assets. As of December 31, 2016, BGE had a regulatory asset of $2 million related to under-recovered natural gas revenue decoupling and $1 million related to under-recovered electric revenue decoupling. 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.

For Pepco and DPL, these amounts represents the electric distribution costs recoverable from customers under Pepco s Maryland and District of Columbia decoupling mechanisms and DPL s Maryland decoupling mechanism. Pepco and

DPL earn a return on these regulatory assets.

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COPCO acquisition adjustment. On July 19, 2007, the MDPSC issued an order which provided for the recovery of a portion of DPL s goodwill. As a result of this order, $41 million in DPL goodwill was transferred to a regulatory asset. This item is being amortized from August 2007 through August 2018. DPL earns a return of 12.95% on these regulatory assets.

Recoverable workers compensation and long-term disability costs. These amounts represent accrued workers compensation and long-term disability costs for Pepco, which are recoverable from customers when actual claims are paid to employees. Pepco is not earning a return on the recovery of these costs and the recovery period is over the life of the associated assets.

Vacation accrual. These amounts represent accrued vacation costs for PECO, DPL and ACE. PECO, DPL and ACE do not earn a return on these regulatory assets and the costs are recoverable from customers when actual payments are made to employees or when vacation is taken.

Securitized stranded costs. These amounts represent certain contract termination payments under a contract between ACE and an unaffiliated non-utility generator and costs associated with the regulated operations of ACE s electricity generation business that are no longer recoverable through customer rates (collectively referred to as stranded costs). The stranded costs are amortized over the life of Transition Bonds issued by Atlantic City Electric Transition Funding LLC (ACE Funding) to securitize the recoverability of these stranded costs. These bonds mature between 2017 and 2023. A customer surcharge is collected by ACE to fund principal and interest payments on the Transition Bonds. PHI earns a return on these regulatory assets.

CAP arrearage. These amounts represent the guaranteed recovery of PECO s previously incurred bad debt expense associated with the eligible CAP accounts receivable balances under the IPAF Program as provided by the 2015 electric distribution rate case settlement. These costs are amortized as recovery is received through a combination of customer payments over the duration of the five-year payment agreement term and rate recovery, including through future rate cases if necessary. PECO is not earning a return on this regulatory asset.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs for the Regulatory Agreement Units that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will be sufficient to fund the associated future decommissioning costs at the time of decommissioning. Exelon is not accruing interest on these costs. See Note 16 Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd, BGE, PHI, Pepco, DPL and ACE have received from customers through depreciation rates to cover the future non-legally required cost of removal of property, plant and equipment which reduces rate base for ratemaking purposes. This liability is reduced as costs are incurred. PHI, Pepco, DPL, and ACE have a regulatory asset which represents removal costs incurred in excess of amounts received from customers through depreciation rates recoverable from ratepayers. Pepco, DPL and ACE do not earn a return on these regulatory assets and the recovery period is over the life of the associated assets.

Deferred rent. Represents the regulatory liability recorded at Exelon and PHI for deferred rent related to a lease. The costs of the lease are recoverable through the ratemaking process at Pepco, DPL and ACE.

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DLC program costs. The DLC program costs include equipment, installation, and information technology costs necessary to implement the DLC Program under PECO s EE&C Phase I Plans. PECO received full cost recovery through Phase I collections and will amortize the costs as a credit to the income statement to offset the related depreciation expense during the same period through September 2025, which is the remaining useful life of the assets. PECO is not paying interest on these over-recovered costs.

Electric distribution tax repairs. PECO s 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. PECO s 2015 electric distribution rate case settlement requires PECO to pay interest on the unamortized balance of the tax-effected catch-up deduction beginning January 1, 2016.

Gas distribution tax repairs. PECO s 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits began being reflected in customer bills on January 1, 2013. No interest will be paid to customers.

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

The following table illustrates our authorized amounts capitalized for ratemaking purposes related to earnings on shareholders investment that are not recognized for financial reporting purposes on our Consolidated Balance Sheets. These amounts will be recognized as revenues in our Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

					Successor			
	Exelon	**ComEd [(a)]**	**PECO**	**BGE [(b)]**	**PHI**	**Pepco [(b)]**	**DPL [(b)]**	**ACE**
December 31, 2016	$ 72	$ 5	$	$ 57	$ 10	$ 6	$ 4	$
					Predecessor			
	Exelon	**ComEd [(a)]**	**PECO**	**BGE [(b)]**	**PHI**	**Pepco [(b)]**	**DPL [(b)]**	**ACE**
December 31, 2015	$ 55	$ 6	$	$ 49	$ 4	$ 1	$ 3	$

(a) Reflects ComEd s unrecognized equity returns earned for ratemaking purposes on its under-recovered distribution services costs regulatory assets.
(b) BGE s, Pepco s and DPL s authorized amounts capitalized for ratemaking purposes related to earnings on shareholders investment on their respective AMI Programs.

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 primarily to recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables

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at face value and is permitted to recover uncollectible accounts expense, including those from Third Party Suppliers, from customers through distribution rates. ACE purchases receivables at face value. ACE recovers all uncollectible accounts expense, including those from Third Party Suppliers, through the Societal Benefits Charge (SBC) rider, which includes uncollectible accounts expense as a component. The SBC is filed annually with the NJBPU. Exelon, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon s, ComEd s, PECO s, BGE s, PHI s, Pepco s, DPL s and ACE s Consolidated Balance Sheets. The following tables provide information about the purchased receivables of those companies as of December 31, 2016 and December 31, 2015.

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

					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.

4. Mergers, Acquisitions, and Dispositions (Exelon, Generation, PHI, DPL 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.

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Regulatory Matters

Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey, and Maryland include a most favored nation provision which, generally speaking, requires allocation of merger benefits proportionally across all the jurisdictions.

During the third and fourth quarters of 2016, Exelon and PHI filed proposals in Delaware, New Jersey and Maryland for amounts and allocations reflecting the application of the most favored nation provision, resulting in a total nominal cost of commitments of $513 million excluding renewable generation commitments (approximately $444 million on a net present value basis, excluding renewable generation commitments and charitable contributions). These filings, which reflect agreements reached with certain parties to the merger proceedings in the jurisdictions, were subject to regulatory review and approval in each jurisdiction. The DPSC and NJBPU approved the amounts and allocations during the third and fourth quarters of 2016. An order from the MDPSC is expected in the first quarter of 2017. No changes in commitment cost levels are required in the District of Columbia.

During the fourth quarter of 2016, the MDPSC approved a change in the application of $9 million in funding for energy-efficiency program support in the DPL MD service territory. This resulted in an adjustment to the merger commitment costs recorded at Exelon Corporate and DPL. Exelon Corporate recorded a decrease and DPL recorded an increase of $9 million in Operating and maintenance expense.

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 year ended December 31, 2016 and PHI s successor period:

Description	Expected Payment Period	Pepco [a]	DPL [a]	ACE [a]	*Successor* PHI [a]	Exelon [a]
Rate credits	2016 - 2017	$ 91	$ 67	$ 101	$ 259	$ 259
Energy efficiency	2016 - 2021					111
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	$ 86	$ 111	$ 323	$ 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.

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

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

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 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, 2016, the Sierra Club and CCAN filed a notice of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court s judgment. The OPC and Sierra Club have until the later of (i) 30 days from the date of the Court s order or (ii) 15 days from the date the Court enters its mandate, to file their petition for further review in the Court of Appeals. Exelon cannot predict if the petition will be filed.

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. The Court has issued a scheduling order, and a decision is expected in the second or third quarter of 2017. Exelon believes the matters are without merit.

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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. Exelon expects to finalize these amounts in the first quarter of 2017. During the second, third and fourth quarters of 2016, certain modifications were made to preliminary valuation amounts for acquired property, plant and equipment, unamortized energy contracts, current liabilities, long-term debt, deferred income taxes and pension and OPEB liabilities resulting in an $11 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.

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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	4,005
Total assets	$ 21,797
Current liabilities	$ 2,752
Unamortized energy contracts	1,515
Regulatory liabilities	297
Long-term debt, including current maturities	5,636
Deferred income taxes	3,447
Pension and OPEB liabilities	821
Other liabilities	187
Total liabilities	$ 14,655
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 tax deductible.

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

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

Through its wholly-owned rate regulated utility subsidiaries, most of PHI s assets and liabilities are subject to cost-of-service rate regulation. Under such regulation, rates charged to customers are established by a regulator to provide for recovery of costs and a fair return on invested capital, or rate

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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 3 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 December 31, 2016. The difference between the contract price and the market price at the acquisition date of the Merger was recognized for each contract as either an intangible asset or liability. In total, Exelon and PHI recorded a net $1.5 billion liability reflecting out-of-the-money contracts. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. In certain instances, the valuations were based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power prices and the discount rate. The unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchase power and fuel expense or Operating revenues, as applicable, over the life of the applicable contract in relation to the present value of the underlying cash flows as of the merger date.

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 $3,785 million and Net loss of $(66) million during the year ended December 31, 2016.

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

	For the Year Ended December 31,	
Acquisition, Integration and Financing Costs [a]	**2016**	**2015**
Exelon [b]	$ 143	$ 87
Generation	37	24
ComEd [c]	(6)	9
PECO	5	4
BGE [c]	(1)	5
Pepco [c]	28	3
DPL [c]	20	2
ACE	19	1

	Successor	*Predecessor*	
Acquisition, Integration and Financing Costs [a]	**March 24, 2016 to December 31, 2016**	**January 1, 2016 to March 23, 2016**	**For the Year Ended December 31, 2015**
PHI[c]	$ 69	$ 29	$ 19

(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 year ended December 31, 2016, includes the reversal of previously incurred acquisition, integration and financing costs of $8 million, $6 million, $11 million, $4 million, and $16 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 3 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.

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.

	Year Ended December 31,	
	2016 (a)	**2015 (b)**
Total operating revenues	$ 32,342	$ 33,823
Net income attributable to common shareholders	1,562	2,618
Basic earnings per share	$ 1.69	$ 2.85
Diluted earnings per share	1.69	2.84

(a) The amounts above exclude non-recurring costs directly related to the merger of $680 million and intercompany revenue of $171 million for year ended December 31, 2016.

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

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 December 31, 2016, Generation had remitted $235 million to ConEdison Solutions and the remaining balance of $22 million, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets, will be paid during the first quarter of 2017.

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

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

The purchase price equaled the estimated fair value of the net assets acquired and the liabilities assumed and, therefore, no goodwill or bargain purchase was recorded as of December 31, 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.

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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 838 MW 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. The NRC license for FitzPatrick expires in 2034. In November 2015, Entergy had announced plans 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.

Closing of the transaction is currently anticipated to occur in the first half of 2017 and requires 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 had been completed) and other customary closing conditions. On November 17, 2016 the NYPSC issued an order approving the transaction. 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 FERC proceeding filed any protests or comments. On December 7, 2016 FERC approved Generation s acquisition of the FitzPatrick facility and dismissed the Public Citizen protest. Public Citizen filed a request for rehearing on January 6, 2017. NRC is the final regulatory approval required to close the transaction and is anticipated during the first half of 2017.

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.

As of December 31, 2016, Generation has recorded $127 million of purchase price consideration in Other noncurrent assets on Exelon s and Generation s Consolidated Balance Sheets. The cash outflows associated with these amounts are reflected within Acquisition of businesses on Exelon s and Generation s Consolidated Statements of Cash Flows. In the event the acquisition does not close, these amounts would be subject to potential write-off to Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. For the year ended December 31, 2016, Exelon and Generation incurred $19 million of merger and integration related costs which are included within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

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Acquisition of Integrys Energy Services, Inc. (Exelon and Generation)

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (IES) for a purchase price of $332 million including net working capital. Generation has elected to account for the transaction as an asset acquisition for federal income tax purposes. The generation and solar asset businesses of Integrys are excluded from the transaction. The Purchase Agreement also includes various representations, warranties, covenants, indemnification and other provisions customary for a transaction of this nature.

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the Integrys acquisition by Generation:

Total consideration transferred	$ 332
Identifiable assets acquired and liabilities assumed	
Working capital assets	$ 390
Mark-to-market derivative assets	184
Unamortized energy contract assets	115
Customer relationships	50
Working capital liabilities	(196)
Mark-to-market derivative liabilities	(57)
Unamortized energy contract liabilities	(110)
Deferred tax liability	(16)
Total net identifiable assets, at fair value	$ 360
Bargain purchase gain (after-tax)	$ 28

The after-tax bargain purchase gain of $28 million is primarily the result of IES executing additional contract volumes between the date the acquisition agreement was signed and the closing of the transaction resulting in an increase in the fair value of the net assets acquired as of the acquisition date. The after-tax gain is included within Gain on consolidation and acquisition of businesses in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

IES s operating revenues and net loss included in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income for the period from November 1, 2014 to December 31, 2014 were $386 million and $(42) million, respectively. The net loss for the period from November 1, 2014 to December 31, 2014 includes pre-tax unrealized losses on derivative contracts of $108 million and the bargain purchase gain of $28 million. It is impracticable to determine the overall financial statement impact of IES for 2015 and 2016 due to the integration of the business into ongoing operations. For the years ended December 31, 2015, and 2014, Exelon and Generation incurred $5 million and $7 million, respectively, of merger and integration related costs which are included within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

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Asset Divestitures (Exelon, Generation, PHI, Pepco and DPL)

On November 10, 2015, Pepco completed the sale of a 3.5 acre parcel of unimproved land (held as non-utility property) in the Buzzard Point area of southeast Washington, D.C., resulting in a pre-tax gain of $37 million.

On December 31, 2015, Pepco completed the sale of a 3.8 acre parcel of unimproved land (held as non-utility property) in the NoMa area of northeast Washington, D.C., resulting in a pre-tax gain of $9 million. The purchase and sale agreement also provided the third party with a 90-day option to purchase the remaining 1.8 acre land parcel.

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 remaining 1.8 acre land parcel noted above, located in the NoMa area of northeast 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 Exelon s and PHI 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 14 Debt and Credit Agreements for more information. In December 2016, Generation sold substantially all of the Upstream assets for $37 million which resulted in a pre-tax loss on sale of $10 million which is included in Gain (loss) on sales of assets on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income for the year ended 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. In December 2016, DPL completed the sale of a 48 acre land parcel located in Middletown, DE, resulting in a pre-tax gain of approximately $5 million. Due to the fair value adjustments recorded at Exelon and PHI as part of purchase accounting, no gain was recorded in Exelon s and PHI s Consolidated Statements of Operations and Comprehensive Income.

During the fourth quarter, as part of its continual assessment of growth and development opportunities, Generation has reevaluated and in certain instances terminated or renegotiated certain projects and contracts. As a result a pre-tax loss of $69 million was recorded within Loss on sale of assets and pre-tax impairment charges of $23 million were recorded within Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income.

5. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)

Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 27 Related Party Transactions.

On April 1, 2014, Generation and subsidiaries of Generation and CENG entered into a Nuclear Operating Services Agreement (NOSA) pursuant to which Generation will operate the CENG nuclear

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generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDF s rights as a member of CENG (the Integration Transaction). CENG will reimburse Generation for its direct and allocated costs for such services. As part of the arrangement, Nine Mile Point Nuclear Station, LLC, a subsidiary of CENG, also assigned to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with Long Island Power Authority, the Unit 2 co-owner. In addition, on April 1, 2014, the Power Services Agency Agreement (PSAA) was amended and extended until the permanent cessation of power generation by the CENG generation plants.

In addition, on April 1, 2014, Generation made a $400 million loan to CENG, bearing interest at 5.25% per annum and payable out of specified available cash flows of CENG or payable upon the maturity date of April 1, 2034. Immediately following receipt of the proceeds of such loan, CENG made a $400 million special distribution to EDF. Unpaid principal and accrued interest on the loan was $316 million as of December 31, 2016.

Exelon, Generation, and subsidiaries of Generation, EDF and CENG also executed a Fourth Amended and Restated Operating Agreement for CENG on April 1, 2014, pursuant to which, among other things, CENG committed to make preferred distributions to Generation (after repayment of the $400 million loan and associated interest) quarterly out of specified available cash flows until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from April 1, 2014 (Preferred Distribution Rights).

Generation and EDF also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDF has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF s 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation s rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation s rights to other distributions. Under limited circumstances, the period for exercise of the put option may be extended for 18 months. In order to exercise its option, EDF must give 60 days advance written notice to Generation stating that it is exercising its option. As of the date these financial statements were issued, EDF has not given notice to Generation that it is exercising its option.

On April 1, 2014, Generation also executed an Indemnity Agreement pursuant to which Generation indemnified 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.

In addition, on April 1, 2014, Generation, EDF, CENG and Nine Mile Point Nuclear Station, LLC entered into an Employee Matters Agreement (EMA) that provides for the transfer of CENG employees to Exelon or one of its affiliates and Exelon s assumption of the sponsorship of the employee benefit plans (including certain incentive, health and welfare, and postemployment benefit plans, among others) and their related trusts by Exelon as the plan sponsor as of July 14, 2014. The EMA also generally requires CENG to fund the obligation related to pre-transfer service of employees, including the underfunded balance of the pension and other postretirement welfare benefit plans measured as of July 14, 2014 by making periodic payments to Generation. These payments will be made on an agreed payment schedule or upon the occurrence of certain specified events, such as EDF s disposition of a

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majority of its interest in CENG. However, in the event that EDF exercises its rights under the Put Option, all payments not made as of the put closing date shall accelerate to be paid immediately prior to such closing date.

As a condition to obtaining regulatory approval for the NOSA and related transactions from the NRC, Exelon executed a support agreement pursuant to which Exelon may be required under specified circumstances to provide up to $245 million of financial support to CENG (Exelon Support Agreement). The Exelon Support Agreement supersedes a previous support agreement under which Generation had agreed to provide up to $205 million of financial support for CENG. In addition, Exelon executed a Guarantee pursuant to which Exelon may be required under specified circumstances to provide up to $165 million in additional financial support for CENG. A previous support agreement executed by an affiliate of EDF remains in effect under which the EDF affiliate may be required to provide up to approximately $145 million of financial support for CENG under specified circumstances. The agreements were executed on April 1, 2014 when the NRC licenses were transferred to Generation. No liability has been recognized by Exelon for the guarantees.

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through March 31, 2014, Generation recorded $19 million of equity in losses of unconsolidated affiliates related to its investment in CENG and recorded $17 million of revenues from CENG. The book value of Generation s investment in CENG prior to the consolidation was $1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was $116 million, net of taxes of $77 million.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon s and Generation s Consolidated Financial Statements between CENG and Exelon s affiliates that are considered related party transactions to Generation. As further described in Note 27 Related Party Transactions, EDF and Generation had a PPA with CENG under which they purchased 15% and 85%, respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs through December 31, 2014. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, CENG s sales to Generation have been eliminated in consolidation. For the years ended December 31, 2016, 2015, and 2014 Generation had sales to EDF of $376 million, $488 million, and $137 million respectively. See discussion above and Note 2 Variable Interest Entities for additional information regarding other transactions between CENG and EDF included within Exelon and Generation s consolidated financial statements and for additional information about the Registrants VIE s.

Accounting for the Consolidation of CENG

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF s noncontrolling interests in CENG at fair value on Exelon s and Generation s Consolidated Balance Sheets. As a result of the consolidation, Exelon and Generation recorded a net gain of $261 million within their respective Consolidated Statements of Operations and Comprehensive Income. This gain consists of approximately $136 million related to the step up to fair value basis of Generation s ownership interest in CENG, and approximately $132 million related to the settlement of pre-existing transactions between CENG and Generation. The net gain on the consolidation of CENG of

$261 million is net of a $7 million payment to EDF.

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The fair value of CENG s assets and liabilities recorded in consolidation was 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 market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The valuations necessary to assess the fair values of certain assets and liabilities were considered preliminary as a result of the short time period between the execution of the NOSA and the end of the second quarter of 2014. The estimates of the fair value of assets and liabilities could be modified for up to one year from April 1, 2014, as more information was obtained about the fair value of assets and liabilities. The principal items that have been revised include the asset retirement obligation liabilities and related asset retirement costs. These items have been updated with inputs from a third party engineering firm with corresponding adjustments recorded in 2014 and the first quarter of 2015. See Note 16 Asset Retirement Obligations for discussion of the impacts of adjustments recorded during 2014 and 2015 related to updated estimates of the CENG asset retirement obligation liabilities. In the period of such revisions, these and any other material changes to the fair value assessments have resulted in adjustments to the amounts recorded upon consolidation. In addition, the asset or liability adjustments impacting depreciation and/or accretion expense recorded after the consolidation date have impacted Generation s post-consolidation results of operations.

Generation recorded the assets and liabilities of CENG at fair value as of April 1, 2014. The following assets and liabilities of CENG were recorded within Generation s Consolidated Balance Sheets as of the date of integration, adjusted for the modifications discussed above:

Fair Values	**Exelon and Generation**
Current assets	$ 499
Nuclear decommissioning trust fund	1,955
Property, plant and equipment	3,073
Nuclear fuel	482
Other assets	10
Total assets	6,019
Current liabilities	237
Asset retirement obligation	1,816
Pension and other employee benefit obligations	281
Unamortized energy contract liabilities	171
Other liabilities	114
Total liabilities	2,619

Total net assets	$	3,400

Generation also recorded the fair value of the noncontrolling interests on its Consolidated Balance Sheets of approximately $1.5 billion, net of the fair value of $152 million for certain specified additional distribution rights under the Operating Agreement. In addition, the noncontrolling interests was further reduced by the $400 million special cash distribution to EDF.

Due to the Preferred Distribution Rights that Generation has on CENG s available cash, the earnings attributable to the noncontrolling interests on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interests on the

Combined Notes to Consolidated Financial Statements (Continued)

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Consolidated Balance Sheets will not be in proportion to Generation s and EDF s equity ownership interests. Rather, the attribution will consider Generation s Preferred Distribution Rights and allocate net income based on each owner s rights to CENG s net assets. For the years ended December 31, 2016 and 2015, Generation reduced by $20 million and $18 million, respectively, the amount of Net income attributable to noncontrolling interests on Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income includes CENG s incremental operating revenues of $548 million and $509 million and CENG s net income (loss), prior to any intercompany eliminations and any adjustments for noncontrolling interests, of $201 million and $(11) million during the years ended December 31, 2016 and 2015, respectively.

Exelon and Generation incurred no merger integration-related costs in 2016. However, in 2015 Exelon and Generation incurred $2 million of merger related integration costs. The costs incurred are classified primarily within Operating and maintenance expense in Exelon s and Generation s respective Consolidated Statements of Operations and Comprehensive Income.

6. Accounts Receivable (All Registrants)

Accounts receivable at December 31, 2016 and 2015 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

						Successor			
2016	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Unbilled customer revenues	$ 1,673	$ 910[(a)]	$ 219	$ 140	$ 182	$ 222	$ 123	$ 58	$ 41
Allowance for uncollectible accounts [(b)]	(334)	(91)	(70)	(61)[(c)]	(32)	(80)[(d)]	(29)[(d)]	(24)[(d)]	(27)[(d)]

						Predecessor			
2015	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**	**PHI**	**Pepco**	**DPL**	**ACE**
Unbilled customer revenues	$ 1,203	$ 732[(a)]	$ 218	$ 105	$ 148	$ 177	$ 93	$ 45	$ 39
Allowance for uncollectible accounts [(b)]	(284)	(77)	(75)	(83)[(c)]	(49)	(56)	(17)	(17)	(17)

(a) Represents unbilled portion of retail receivables estimated under Exelon s unbilled critical accounting policy.
(b) Includes the allowance for uncollectible accounts on customer and other accounts receivable.

(c) Excludes the non-current allowance for uncollectible accounts of $23 million and $8 million at December 31, 2016 and 2015, respectively, related to PECO s current installment plan receivables described below.

(d) At December 31, 2016, as explained in Note 1 Significant Accounting Policies, PHI, Pepco, DPL and ACE estimated the allowance for uncollectible accounts on customer receivables by applying loss rates to the outstanding receivable balance by risk segment. The change in estimate resulted in an overall increase of $30 million, $14 million, $8 million, and $8 million in the allowance for uncollectible accounts with $20 million, $8 million, $4 million, and $8 million deferred as a regulatory asset on PHI s, Pepco s, DPL s and ACE s Consolidated Balance Sheets at December 31, 2016, respectively. This also resulted in a $10 million, $6 million, and $4 million pre-tax charge to provision for uncollectible accounts expense for the year ended December 31, 2016, which is included in Operating and maintenance expense on PHI s, Pepco s, and DPL s Consolidated Statements of Operations and Comprehensive Income, respectively.

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

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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 $9 million and $15 million at December 31, 2016 and 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. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2016 of $13 million consists of $1 million, $3 million and $9 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance associated with these receivables 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 December 31, 2016 and 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.

7. Property, Plant and Equipment (All Registrants)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric transmission and distribution	5-90	$ 45,698	$ 32,546
Electric generation	3-56	27,193	25,615
Gas transportation and distribution	5-90	4,642	3,864
Common electric and gas	4-50	1,312	1,149
Nuclear fuel (a)	1-8	6,546	6,384
Construction work in progress	N/A	4,306	3,075
Other property, plant and equipment (b)	3-50	1,027	1,181
Total property, plant and equipment		90,724	73,814
Less: accumulated depreciation (c)		19,169	16,375
Property, plant and equipment, net		$ 71,555	$ 57,439

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,326 million and $1,266 million at December 31, 2016 and 2015, respectively.

(b) Includes Generation s buildings under capital lease with a net carrying value of $10 million and $13 million at December 31, 2016 and 2015, respectively. The original cost basis of the buildings was $52 million, and total accumulated amortization was $42 million and $39 million, as of December 31, 2016 and 2015, respectively. Also includes ComEd s buildings under capital lease with a net carrying value at both December 31, 2016 and 2015, of $7 million. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2016 and 2015. Includes land held for future use and non utility property at ComEd, PECO, BGE, Pepco, DPL, and ACE of $60 million, $21 million, $32 million, $66 million, $16 million, and $27 million, respectively, at December 31, 2016. At December 31, 2015

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these balances also include capitalized acquisition, development and exploration costs of $266 million related to oil and gas production activities at Generation, see Note 4 Mergers, Acquisitions, and Dispositions for additional information regarding the sale of upstream assets. Includes the original cost and progress payments associated with Generation s turbine equipment held for future use with a carrying value of $17 million and $146 million at December 31, 2016 and 2015, respectively. See Note 8 Impairment of Long-Lived Assets for additional information on the impairment of Generations turbine equipment.

(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $3,186 million and $2,861 million as of December 31, 2016 and 2015, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	**2016**	**2015**	**2014**
Electric transmission and distribution	2.73%	2.83%	2.93%
Electric generation	5.94%[(a)]	3.47%	3.50%
Gas	2.17%	2.17%	2.13%
Common electric and gas	7.41%	7.79%	7.32%

(a) See Note 9 Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton and Quad Cities.

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	**2016**	**2015**
Asset Category			
Electric generation	3-56	$ 27,193	$ 25,615
Nuclear fuel [(a)]	1-8	6,546	6,384
Construction work in progress	N/A	2,332	2,017
Other property, plant and equipment [(b)]	4	76	466
Total property, plant and equipment		36,147	34,482
Less: accumulated depreciation [(c)]		10,562	8,639
Property, plant and equipment, net		$ 25,585	$ 25,843

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,326 million and $1,266 million at December 31, 2016 and 2015, respectively.

(b) Includes buildings under capital lease with a net carrying value of $10 million and $13 million at December 31, 2016 and 2015, respectively. The original cost basis of the buildings was $52 million, and total accumulated amortization was $42 million and $39 million, as of December 31, 2016 and 2015, respectively. At December 31, 2015 these balances also include capitalized acquisition, development and exploration costs of $266 million related to oil and gas production activities at Generation, see Note 4 Mergers, Acquisitions, and Dispositions for additional information regarding the sale of upstream assets. Includes the original cost and progress payments associated with Generation s turbine equipment held for future use with a carrying value of $17 million and $146 million at December 31, 2016 and 2015, respectively. See Note 8 Impairment of Long-Lived Assets for additional information on the impairment of Generations turbine equipment.

(c) Includes accumulated amortization of nuclear fuel in the reactor core of $3,186 million and $2,861 million as of December 31, 2016 and 2015, respectively.

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The annual depreciation provisions as a percentage of average service life for electric generation assets were 5.94%, 3.47% and 3.50% for the years ended December 31, 2016, 2015 and 2014, respectively. See Note 9 Early Nuclear Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton and Quad Cities.

License Renewals. Generation s depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek and Clinton) and the hydroelectric generating stations. As a result, the receipt of license renewals has no material impact on the Consolidated Statements of Operations and Comprehensive Income. Oyster Creek depreciation provisions are based on the 2019 expected shutdown date. Clinton depreciation provisions are based on 2027 which is the last year of the Illinois ZECs. See Note 3 Regulatory Matters for additional information regarding license renewals and the Illinois ZECs. See Note 9 Early Nuclear Plant Retirements for additional information on the impacts of expected and potential early plant retirement.

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric transmission and distribution	5-80	$ 22,636	$ 20,576
Construction work in progress	N/A	569	572
Other property, plant and equipment [(a), (b)]	37-50	67	64
Total property, plant and equipment		23,272	21,212
Less: accumulated depreciation		3,937	3,710
Property, plant and equipment, net		$ 19,335	$ 17,502

(a) Includes buildings under capital lease with a net carrying value at both December 31, 2016 and 2015 of $7 million. The original cost basis of the buildings was $8 million and total accumulated amortization was $1 million as of both December 31, 2016 and 2015.
(b) Includes land held for future use and non-utility property.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 3.03%, 3.03% and 3.05% for the years ended December 31, 2016, 2015 and 2014, respectively.

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PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric transmission and distribution	5-65	$ 7,591	$ 7,230
Gas transportation and distribution	5-70	2,348	2,206
Common electric and gas	5-50	670	631
Construction work in progress	N/A	188	154
Other property, plant and equipment [(a)]	50	21	21
Total property, plant and equipment		10,818	10,242
Less: accumulated depreciation		3,253	3,101
Property, plant and equipment, net		$ 7,565	$ 7,141

(a) Represents land held for future use and non-utility property.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2016	2015	2014
Electric transmission and distribution	2.32%	2.39%	2.55%
Gas	1.82%	1.87%	1.84%
Common electric and gas	5.11%	5.16%	5.16%

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015

Asset Category			
Electric transmission and distribution	5-90	$ 7,067	$ 6,663
Gas distribution	5-90	2,170	1,951
Common electric and gas	5-40	707	655
Construction work in progress	N/A	318	312
Other property, plant and equipment [(a)]	20	32	32
Total property, plant and equipment		10,294	9,613
Less: accumulated depreciation		3,254	3,016
Property, plant and equipment, net		$ 7,040	$ 6,597

(a) Represents land held for future use and non-utility property.

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The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	**2016**	**2015**	**2014**
Electric transmission and distribution	2.56%	2.62%	2.96%
Gas	2.45%	2.50%	2.47%
Common electric and gas	9.45%	10.35%	9.49%

PHI

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	*Successor* **2016**	*Predecessor* **2015**
Asset Category			
Electric transmission and distribution	5-86	$ 10,315	$ 14,563
Gas distribution	5-75	414	547
Common electric and gas	4-40	65	164
Construction work in progress	N/A	892	591
Other property, plant and equipment [(a)]	3-43	107	339
Total property, plant and equipment		11,793	16,204
Less: accumulated depreciation		195	5,340
Property, plant and equipment, net		$ 11,598	$ 10,864

(a) Represents plant held for future use and non-utility property. Utility plant is generally subject to a first mortgage lien.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	**2016**	**2015**	**2014**
Electric transmission and distribution	2.52%	2.48%	2.42%

Gas	2.57%	2.55%	2.48%
Common electric and gas	8.12%	5.19%	4.55%

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Pepco

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2016 and 2015:

	Average Service Life (years)	2016	2015
Asset Category			
Electric transmission and distribution	5-86	$ 8,018	$ 7,682
Construction work in progress	N/A	537	318
Other property, plant and equipment [(a)]	10-33	66	91
Total property, plant and equipment		8,621	8,091
Less: accumulated depreciation		3,050	2,929
Property, plant and equipment, net			