EXELON Corp
Form 10-K
February 08, 2019
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Commission File Number	Name of Registrant; State or Other Jurisdiction of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
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.	52-2297449

	Washington, District of Columbia 20068 (202) 872-2000	
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

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

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, $0.01 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	x	No	o
Exelon Generation Company, LLC	Yes	x	No	o
Commonwealth Edison Company	Yes	x	No	o
PECO Energy Company	Yes	x	No	o
Baltimore Gas and Electric Company	Yes	x	No	o
Pepco Holdings LLC	Yes	x	No	o
Potomac Electric Power Company	Yes	o	No	x
Delmarva Power & Light Company	Yes	o	No	x
Atlantic City Electric Company	Yes	o	No	x

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý 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 ý 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. ý

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

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

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

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

The estimated aggregate market value of the voting and non-voting common equity held by nonaffiliates of each registrant as of June 30, 2018 was as follows:

Exelon Corporation Common Stock, without par value	$41,118,095,431
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, 2019 was as follows:

Exelon Corporation Common Stock, without par value	969,745,933
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,021,331
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000
Pepco Holdings LLC	Not applicable
Potomac Electric Power Company Common Stock, $0.01 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 2019 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2019 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.

TABLE OF CONTENTS

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
DPL	Delmarva Power & Light Company
ACE	Atlantic City Electric Company
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, ACE, PES and PCI collectively
ACE Funding or ATF	Atlantic City Electric Transition Funding LLC
Antelope Valley	Antelope Valley Solar Ranch One
BondCo	RSB BondCo LLC
BSC	Exelon Business Services Company, LLC
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
EEDC	Exelon Energy Delivery Company, LLC
EGR IV	ExGen Renewables IV, LLC
EGRP	ExGen Renewables Partners, LLC
EGTP	ExGen Texas Power, LLC
Entergy	Entergy Nuclear FitzPatrick, LLC
Exelon Corporate	Exelon in its corporate capacity as a holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
FitzPatrick	James A. FitzPatrick nuclear generating station
PCI	Potomac Capital Investment Corporation and its subsidiaries
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
Pepco Energy Services or PES	Pepco Energy Services, Inc. and its subsidiaries
PHI Corporate	PHI in its corporate capacity as a holding company
PHISCO	PHI Service Company
RPG	Renewable Power Generation
SolGen	SolGen, LLC
TMI	Three Mile Island nuclear facility
UII	Unicom Investments, Inc.

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
AGE	Albany Green Energy Project
AMI	Advanced Metering Infrastructure
AMP	Advanced Metering Program
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Alternative Revenue Program
ASA	Asset Sale Agreement
BGS	Basic Generation Service
CAISO	California ISO
CAP	Customer Assistance Program
CCGTs	Combined-Cycle gas turbines
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CES	Clean Energy Standard
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI and the parent of DPL and ACE during the Predecessor periods
Conectiv Energy	Conectiv Energy Holdings, Inc. and substantially all of its subsidiaries, which were sold to Calpine in July 2010
ConEdison Solutions	The competitive retail electricity and natural gas business of Consolidated Edison Solutions, Inc., a subsidiary of Consolidated Edison, Inc
CSAPR	Cross-State Air Pollution Rule
CTA	Consolidated tax adjustment
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
DC PLUG	District of Columbia Power Line Undergrounding Initiative
DCPSC	District of Columbia Public Service Commission
DDOT	District Department of Transportation
DOE	United States Department of Energy
DOEE	Department of Energy & Environment
DOJ	United States Department of Justice
DPSC	Delaware Public Service Commission
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA and its subsidiaries
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
EmPower	A Maryland demand-side management program for Pepco and DPL
EPA	United States Environmental Protection Agency

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

EPSA	Electric Power Supply Association
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
FASB	Financial Accounting Standards Board
FEJA	Illinois Public Act 99-0906 or Future Energy Jobs Act
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GAAP	Generally Accepted Accounting Principles in the United States
GCR	Gas Cost Rate
GHG	Greenhouse Gas
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IIP	Infrastructure Investment Program
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
LLRW	Low-Level Radioactive Waste
LNG	Liquefied Natural Gas
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

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
n.m.	not meaningful
NAAQS	National Ambient Air Quality Standards
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
NLRB	National Labor Relations Board
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOSA	Nuclear Operating Services Agreement
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NSPS	New Source Performance Standards
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
NYPSC	New York Public Service Commission
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPC	Office of People’s Counsel
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
PCB	Polychlorinated Biphenyl
PGC	Purchased Gas Cost Clause
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
Preferred Stock	Originally issued shares of non-voting, non-convertible and non-transferable Series A preferred stock, par value $0.01 per share
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
RNF	Revenue Net of Purchased Power and Fuel Expense
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
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SGIG	Smart Grid Investment Grant from DOE
SILO	Sale-In, Lease-Out
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPFPA	Security, Police and Fire Professionals of America
SPP	Southwest Power Pool
TCJA	Tax Cuts and Jobs Act
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

Table of Contents

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.
CAUTIONARY STATEMENTS REGARDING FORWARD-LOOKING INFORMATION
This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, including those factors discussed with respect to the Registrants 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 22, Commitments and Contingencies; 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 SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements, and other information that the Registrants file electronically with the SEC. These documents are also available to the public from commercial document retrieval services and the Registrants' website at www.exeloncorp.com. Information contained on the Registrants' website shall not be deemed incorporated into, or to be a part of, this Report.

Table of Contents

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.

Name of Registrant	State/Jurisdiction and Year of Incorporation	Business	Service Territories	Address of Principal Executive Offices
Exelon Generation Company, LLC	Pennsylvania (2000)	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions	300 Exelon Way, Kennett Square, Pennsylvania 19348
Commonwealth Edison Company	Illinois (1913)	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago	440 South LaSalle Street, Chicago, Illinois 60605
		Transmission and distribution of electricity to retail customers		
PECO Energy Company	Pennsylvania (1929)	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)	2301 Market Street, Philadelphia, Pennsylvania 19103
		Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)	

Baltimore Gas and Electric Company	Maryland (1906)	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)	110 West Fayette Street, Baltimore, Maryland 21201
		Transmission and distribution of electricity and distribution of natural gas to retail customers		
Pepco Holdings LLC	Delaware (2016)	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE	701 Ninth Street, N.W., Washington, D.C. 20068
Potomac Electric Power Company	District of Columbia (1896) Virginia (1949)	Purchase and regulated retail sale of electricity	District of Columbia and Major portions of Montgomery and Prince George’s Counties, Maryland	701 Ninth Street, N.W., Washington, D.C. 20068
		Transmission and distribution of electricity to retail customers		
Delmarva Power & Light Company	Delaware (1909) Virginia (1979)	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)	500 North Wakefield Drive, Newark, Delaware 19702
		Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)	
Atlantic City Electric Company	New Jersey (1924)	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey	500 North Wakefield Drive, Newark, Delaware 19702
		Transmission and distribution of electricity to retail customers		

Table of Contents

Business Services

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of corporate governance support services including corporate strategy and development, legal, human resources, information technology, finance, real estate, security, corporate communications and supply at cost. The costs of these services are directly charged or allocated to the applicable operating segments. The services are provided pursuant to service agreements. Additionally, the results of Exelon's corporate operations include interest costs and income from various investment and financing activities.

PHISCO, a wholly owned subsidiary of PHI, provides a variety of support services at cost, including legal, finance, 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 PHISCO and the participating operating subsidiaries.

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 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 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. See Note 5 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

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. 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 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.

RTOs and ISOs exist in a number of regions to provide transmission service across multiple transmission systems. FERC has approved PJM, MISO, ISO-NE and SPP as RTOs and CAISO and ISO-NY 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.

8

Table of Contents

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 NERC mandatory reliability standards, which protect the nation’s bulk power system against potential disruptions from cyber and physical security breaches.

CENG

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 (Ginna) and Nine Mile Point. CENG’s ownership share in the total capacity of these units is 4,041 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation and EDF 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. In addition, 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. To date, EDF has not given notice to Generation that it is exercising its option.

Exelon and Generation record all assets, liabilities and EDF’s noncontrolling interests in CENG on a fully consolidated basis in Exelon’s and Generation’s Consolidated Balance Sheets. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information regarding the CENG consolidation.

Acquisitions

Handley Generating Station

On April 4, 2018, Generation acquired the Handley Generating Station in conjunction with the EGTP Chapter 11 proceedings for a total purchase price of $62 million. See EGTP in the Dispositions section below for additional information on EGTP's November 7, 2017 bankruptcy filing.

FitzPatrick

On March 31, 2017, Generation acquired the 838 MW single-unit FitzPatrick plant located in Scriba, New York from Entergy for a total purchase price consideration of $289 million, resulting in an after-tax bargain purchase gain of $233 million in 2017.

ConEdison Solutions

On September 1, 2016, Generation acquired ConEdison Solutions 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.

Table of Contents

Dispositions

EGTP

On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware. As a result of the bankruptcy filing, EGTP's assets and liabilities were deconsolidated from Exelon and Generation's consolidated financial statements. The Chapter 11 bankruptcy proceedings were finalized on April 17, 2018, resulting in the ownership of EGTP assets (other than the Handley Generating Station) being transferred to EGTP's lenders.

Asset Dispositions

During 2015 and 2014, 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. See Note 5 — Mergers, Acquisitions and Dispositions and Note 7 — Impairment of Long-Lived Assets and Intangibles of the Combined Notes to Consolidated Financial Statements for additional information on acquisitions and dispositions.

Generating Resources

At December 31, 2018, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets[(a)(b)]	
Nuclear	19,713
Fossil (primarily natural gas and oil)	9,547
Renewable[(c)]	3,203
Owned generation assets	32,463
Long-term power purchase contracts[(d)]	5,184
Total generating resources	37,647

(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, solar and biomass generating assets.
(d) Electric supply procured under site specific agreements.

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

- 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 34% of capacity).
- Midwest represents operations in the western half of PJM and the United States footprint of MISO, excluding MISO's Southern Region (approximately 37% of capacity).
- New England represents operations within ISO-NE (approximately 7% of capacity).
- New York represents operations within ISO-NY (approximately 6% of capacity).
- ERCOT represents operations within Electric Reliability Council of Texas (approximately 11% of capacity).
- Other Power Regions represents Canada, South and West (approximately 5% of capacity).

Table of Contents

During the first quarter of 2019, due to a change in economics in our New England region, Generation is changing the way that information is reviewed by the CODM. The New England region will no longer be regularly reviewed as a separate region by the CODM nor will it be presented separately in any external information presented to third parties. Information for the New England region will be reviewed by the CODM as part of Other Power Regions. As a result, beginning in the first quarter of 2019, Generation will disclose five reportable segments consisting of Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions. See Note 24 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information.

Nuclear Facilities

Generation has ownership interests in fourteen nuclear generating stations currently in service, consisting of 24 units with an aggregate of 19,713 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for undivided ownership interests in three jointly-owned nuclear stations: Quad Cities (75% ownership), Peach Bottom (50% ownership), and Salem (42.59% ownership), which are consolidated in Exelon’s and Generation's financial statements relative to its proportionate ownership interest in each unit, and a 50.01% membership interest in CENG, which owns Calvert Cliffs, Nine Mile Point [excluding Long Island Power Authority's 18% undivided ownership interest in Nine Mile Point Unit 2] and Ginna nuclear stations. CENG is 100% consolidated in Exelon's and Generation’s financial statements.

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 2018, 2017 and 2016 electric supply (in GWh) generated from the nuclear generating facilities was 68%, 69% and 67%, respectively, of Generation’s total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. Generation’s wholesale and retail power marketing activities are, in part, supplied by the output from the nuclear generating stations. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information of Generation’s electric supply sources.

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. Generation’s operations from its nuclear plants have historically had minimal environmental impact and the plants have a safe operating history.

During 2018, 2017 and 2016, the nuclear generating facilities operated by Generation achieved capacity factors of 94.6%, 94.1% and 94.6%, respectively. The capacity factors reflect ownership percentage of stations operated by Generation and include CENG. 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 power marketing 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 also 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. All nuclear generating stations operated by Generation, except for Peach Bottom Units 2 and 3, are categorized by the NRC in the Licensee Response Column, which is the highest of five performance bands. As of January 29, 2019, the NRC categorized Peach Bottom Units 2 and 3 in the Regulatory Response Column, which is the second highest of five performance bands. 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

Table of Contents

terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures and/or operating costs for nuclear generating facilities.

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.

The following table summarizes the current license expiration dates for Generation's operating 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
FitzPatrick	1	1974	2034
LaSalle	1	1984	2042
	2	1984	2043
Limerick	1	1986	2044
	2	1990	2049
Nine Mile Point	1	1969	2029
	2	1988	2046
Peach Bottom[(c)]	2	1974	2033
	3	1974	2034
Quad Cities	1	1973	2032
	2	1973	2032
Ginna	1	1970	2029
Salem	1	1977	2036
	2	1981	2040
Three Mile Island[(d)]	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) On July 10, 2018, Generation submitted a second 20-year license renewal application to NRC for Peach Bottom Units 2 and 3.

(d) On May 30, 2017, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019 and has notified the NRC. See Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

The operating license renewal process takes approximately four to five years from the commencement of the renewal process, which includes approximately two years for Generation to develop the application and approximately two years for the NRC to review the 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 TMI and Clinton. Beginning in 2017, TMI depreciation provisions are based on its 2019 expected shutdown date. Beginning in 2016, Clinton depreciation provisions are based on an estimated useful life of 2027 which is the last year of the Illinois Zero Emissions Standard. See Note 4 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on FEJA and Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information on early retirements.

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, 2018, Generation had approximately 87,100 SNF assemblies (21,400 tons) stored on site in SNF pools or dry cask storage which 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, and Oyster Creek, which is no longer operational. See the Decommissioning section below for additional information regarding Zion Station and Oyster Creek. All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for TMI, where such storage is projected to be in operation in 2021. 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 22 — 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, which have enough storage capacity to store all Class A LLRW for the life of all stations in Generation's nuclear fleet. 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 Class 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 on-site storage and cost impacts.

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 reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See “Nuclear Insurance” within Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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 statements.

Table of Contents

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. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded in Exelon's and Generation's Consolidated Balance Sheets at December 31, 2018 at fair value of approximately $12.7 billion and have an estimated targeted annual pre-tax return of 5% to 6.2%, while the Nuclear AROs are recorded in Exelon's and Generation's Consolidated Balance Sheets at December 31, 2018 at approximately $10.0 billion and have an estimated annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units. The NDTs and AROs include Oyster Creek balances classified as Assets held for sale and Liabilities held for sale, respectively, in Exelon's and Generation's Consolidated Balance Sheets at December 31, 2018. 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 4 — Regulatory Matters, Note 5 - Mergers, Acquisitions and Dispositions, Note 11 — Fair Value of Financial Assets and Liabilities and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation's NDT funds and its decommissioning obligations.

Oyster Creek Generating Station. On July 31, 2018, Generation entered into an agreement with Holtec International (Holtec) and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), for the sale and decommissioning of Oyster Creek located in Forked River, New Jersey. On September 17, 2018, Oyster Creek permanently ceased generation operations. See Note 5 - Mergers, Acquisitions and Dispositions and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding the sale of Oyster Creek.

Zion Station Decommissioning. On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions, Inc. and its wholly owned subsidiaries, EnergySolutions, LLC and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station.

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 will be deferred until such milestones are met. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station decommissioning and 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, 2018, Generation had ownership interests in 12,750 MW of capacity in generating facilities currently in service, consisting of 9,547 MW of natural gas and oil, and 3,203 MW of renewables (wind, hydroelectric, solar and biomass). Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) Wyman; (2) certain wind project entities and a biomass project entity with minority interest owners; and (3) EGRP which is owned 49% by another owner. 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 Wyman, which is operated by a third party. In 2018, 2017 and 2016, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 11%, 12% and 10%, 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.

Table of Contents

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, which include Generation's Conowingo Hydroelectric Project (Conowingo) and Muddy Run Pumped Storage Facility Project (Muddy Run). Muddy Run's license expires on December 1, 2055. On August 29, 2012, Generation submitted a hydroelectric license application to the FERC for a 46-year license for Conowingo. Based on the FERC procedural schedule, the FERC licensing process for Conowingo was not completed prior to the expiration of the plant’s license on September 1, 2014. As a result, on September 10, 2014, FERC issued an annual license for Conowingo, effective as of the expiration of the previous license. The annual license renews automatically absent any further FERC action. The stations are currently being depreciated over their estimated useful lives, which includes actual and anticipated license renewal periods. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Insurance

Generation maintains business interruption insurance for its renewable projects, but not for its fossil and hydroelectric operations unless required by contract or financing agreements. See Note 13 — 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.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity 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, 2018:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic	14	2019 - 2032	237
Midwest	4	2019 - 2026	834
New England	7	2019 - 2021	40
ERCOT	5	2020 - 2031	1,524
Other Power Regions	11	2019 - 2030	2,549
Total	41		5,184

	2019	2020	2021	2022	2023	Thereafter	Total
Capacity Expiring (MW)	673	1,020	826	298	167	2,200	5,184

Table of Contents

Fuel

The following table shows sources of electric supply in GWh for 2018 and 2017:

	Source of Electric Supply	
	2018	2017
Nuclear[(a)]	185,020	182,843
Purchases — non-trading portfolio	59,154	51,595
Fossil (primarily natural gas and oil)	21,015	22,546
Renewable[(b)]	8,469	7,848
Total supply	273,658	264,832

____

(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 2018 and 2017 includes physical volumes of 35,100 GWh and 34,761 GWh, respectively, for CENG.

(b) Includes wind, hydroelectric, solar and biomass 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 inventory in various forms and 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 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, 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 12 — 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 physical delivery and marketing of power. Generation largely obtains physical power supply from its generating assets and power purchase agreements in multiple geographic regions. Power purchase agreements, including tolling arrangements, are commitments related to power generation of specific generation plants and/or dispatch similar to an owned asset depending on the type of underlying asset. The commodity risks associated with the output from generating assets and PPAs are managed using various commodity transactions including sales to customers. The main objective is to obtain low-cost energy supply to meet physical delivery obligations to both wholesale and retail customers. 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. Where necessary, Generation may also purchase transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs.

Price and 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 may also enter into transactions that are outside of this ratable sales plan.

Generation is exposed to commodity price risk in 2019 and beyond for portions of its electricity portfolio

16

Table of Contents

that are unhedged. As of December 31, 2018, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92%, 56%-59% and 32%-35% for 2019, 2020, and 2021, 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 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. The 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. 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 primarily in nuclear fuel and energy generation assets. Generation’s estimated capital expenditures for 2019 are approximately $2.0 billion, which includes Generation's share of the investment in the co-owned Salem plant and the total capital expenditures for the fully consolidated CENG nuclear plants.

Utility Registrants

Utility Operations

Service Territories and Franchise Agreements

The following table presents the size of service territories, populations of each service territory and the number of customers within each service territory for the Utility Registrants as of December 31, 2018:

	Service Territories (in square miles)			Service Territory Population (in millions)			Number of Customers (in millions)		
	Total	Electric	Natural gas	Total	Electric	Natural gas	Total	Electric	Natural gas
ComEd	11,400	11,400	n/a	9.5 (a)	9.5	n/a	4.0	4.0	n/a
PECO	2,100	1,900	1,900	4.0 (b)	4.0	2.5	1.7	1.6	0.5
BGE	3,250	2,300	3,050	3.1 (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	5,400	5,400	275	1.4 (e)	1.4	0.6	0.5	0.5	0.1
ACE	2,800	2,800	n/a	1.1 (f)	1.1	n/a	0.6	0.6	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.

The Utility Registrants have the necessary authorizations to perform their current business of providing regulated electric and natural gas distribution services in the various municipalities and territories in which they now supply such services. These authorizations include charters, franchises, permits, and certificates of public convenience issued by local and state governments and state utility commissions. ComEd's, BGE's (gas) and ACE's rights are generally non-exclusive; while PECO's, BGE's (electric) Pepco's and DPL's rights are generally exclusive. Certain authorizations are perpetual while others have varying expiration dates. The Utility Registrants anticipate working with the appropriate governmental bodies to extend or replace the authorizations prior to their expirations.

17

Table of Contents

Utility Regulations

State utility commissions regulate the Utility Registrants' electric and gas distribution rates and service, issuances of certain securities, and certain other aspects of the business. The following table outlines the state commissions responsible for utility oversight.

Registrant	Commission
ComEd	ICC
PECO	PAPUC
BGE	MDPSC
Pepco	DCPSC/MDPSC
DPL	DPSC/MDPSC
ACE	NJBPU

The Utility Registrants are public utilities under the Federal Power Act subject to regulation by FERC related to transmission rates and certain other aspects of the utilities' business. The U.S. Department of Transportation also regulates pipeline safety and other areas of gas operations for PECO, BGE and DPL. Additionally, the Utility Registrants are subject to NERC mandatory reliability standards, which protect the nation's bulk power system against potential disruptions from cyber and physical security breaches.

Seasonality Impacts on Delivery Volumes

The Utility Registrants' electric distribution volumes 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 distribution volumes are generally higher during the winter months when cold temperatures create demand for winter heating.

ComEd, BGE, Pepco and DPL Maryland have electric distribution decoupling mechanisms and BGE has a natural gas decoupling mechanism that eliminate the favorable and unfavorable impacts of weather and customer usage patterns on electric distribution and natural gas delivery volumes. As a result, ComEd’s, BGE’s, Pepco’s and DPL’s Maryland electric distribution revenues and BGE's natural gas distribution revenues are not materially impacted by delivery volumes. PECO’s electric distribution revenues and natural gas distribution revenues and ACE’s electric distribution revenues and DPL’s Delaware electric distribution and natural gas revenues are impacted by delivery volumes.

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. 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 customers that choose to purchase electric generation or natural gas from competitive suppliers, the Utility Registrants act as the billing agent and therefore do not record Operating revenues or Purchased power and fuel

Table of Contents

expense related to the electricity and/or natural gas. For customers that choose to purchase electric generation or natural gas from a Utility Registrant, the Utility Registrants are permitted to recover the electricity and natural gas procurement costs without mark-up and therefore record equal and offsetting amounts of Operating revenues and Purchased power and fuel expense related to the electricity and/or natural gas. As a result, fluctuations in electricity or natural gas sales and procurement costs have no impact on the Utility Registrants' Revenues net of purchased power and fuel expense, which is a non-GAAP measure used to evaluate operational performance, or Net Income.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Results of Operations and Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding electric and natural gas distribution services.

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. RTO spot market purchases and sales are utilized to balance the utility electric load and supply as required. 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.

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%, 54% and 34% of PECO's, BGE's and DPL's 2018-2019 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. The off-system gas sales are not material to PECO, BGE and DPL.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK, Commodity Price, for additional information regarding Utility Registrants' contracts to procure electric supply and natural gas.

Energy Efficiency Programs

The Utility Registrants are 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.

The Utility Registrants are allowed to earn a return on their energy efficiency costs. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

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 2019 are as follows:

	Projected 2019 Capital Expenditure Spending			
(in millions)	Transmission	Distribution	Gas	Total
ComEd	325	1,550	N/A	1,875
PECO	125	600	250	975
BGE	225	475	400	1,100
Pepco	75	650	N/A	725
DPL	100	200	50	350
ACE	150	150	N/A	300

Transmission Services

Under FERC’s open access transmission policy, 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 approved by FERC. 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 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 transmission rates and the process for updating the formula rate calculation on an annual basis.

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rate and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The new formula was accepted by FERC effective as of December 1, 2017, subject to refund and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge.

See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding the PECO transmission formula rate and transmission services.

Table of Contents

Employees

As of December 31, 2018, Exelon and its subsidiaries had 33,383 employees in the following companies, of which 11,372 or 34% 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)]	1,568	84	2,485	4,137	14,110
ComEd	3,378	—	—	3,378	6,152
PECO	—	1,381	—	1,381	2,708
BGE[(d)]	—	—	—	—	3,025
PHI[(e)]	—	—	277	277	1,258
Pepco[(e)]	—	—	1,023	1,023	1,423
DPL[(e)]	—	—	684	684	940
ACE[(e)]	—	—	386	386	612
Other[(g)]	62	—	44	106	3,155
Total	5,008	1,465	4,899	11,372	33,383

(a) A separate CBA between ComEd and IBEW Local 15 covers approximately 73 employees in ComEd's System Services Group and will expire in 2020. Generation's and ComEd's separate CBAs with IBEW Local 15 will expire in 2022.

(b) 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 84 employees, which expires in 2019.

(c) During 2018, Generation acquired and finalized its CBA with Distrigas Local 369, which will expire in 2020, and additionally, finalized a first collective bargaining agreement, expiring in 2021, with a small unit of employees represented by IUOE Local 501 at Exelon's Hyperion Solutions facility. Also in 2018, Generation finalized a three-year agreement with the Security Officer union at Braidwood and that CBA will expire in 2021. During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at FitzPatrick into one CBA covering both craft and security employees, which will expire in 2023. 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, Generation finalized a 5-year agreement with the New England ENEH, UWUA Local 369, which will expire in 2022. 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 three Security Officer unions at Byron, Clinton and TMI, all expiring between 2019 and 2021, respectively. During 2014, Generation finalized CBAs with TMI Local 777 and Oyster Creek Local 1289, expiring in 2019 and 2021, respectively. Also in 2014, CENG finalized its CBA with Nine Mile Point which will expire in 2020.

(d) In January 2017, an election was held at BGE which resulted in union representation for certain employees, who numbered 1,284 at the end of 2018. BGE and IBEW Local 410 are negotiating 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 CBAs with four local unions. CBAs are generally renegotiated every three to five years. All these CBAs were renegotiated in 2014 and were extended through various dates ranging from October 2018 through June 2020. During 2018, ACE finalized a five-year agreement with Local 210, expiring in 2023.

(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 environmental 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

Table of Contents

President, Corporate Strategy & Chief Innovation and Sustainability Officer; the Senior Vice President, Competitive Market Policy; and the Director, Safety & Sustainability, as well as senior management of Generation, ComEd, PECO, BGE, PHI, 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 Generation Oversight Committee and the Corporate Governance Committee the authority to oversee Exelon’s compliance with health, environmental and safety laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including Exelon’s internal climate change and sustainability policies and programs, as discussed in further detail below. 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 impose restrictions on emission of particulates, sulfur dioxide (SO2), nitrogen oxides (NOx), mercury and other air pollutants and require permits for operation of emitting sources. Such permits have been obtained as needed by Exelon’s subsidiaries. However, due to its low emitting generation fleet comprised of nuclear, natural gas, hydroelectric, wind and solar, compliance with the Federal Clean Air Act does not have a material impact on Generation’s operations. 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 federal 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 Exelon's facilities discharge stormwater and 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 the Delaware River Basin Commission and the Susquehanna River Basin Commission, regional agencies that primarily regulate water usage.

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 recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities and Salem.

On October 14, 2014, the EPA's 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, such as those that would make cooling towers infeasible.

22

Table of Contents

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 before the expiration of its operating license in 2029. On September 17, 2018, Oyster Creek permanently ceased generation operations, and its cooling water intake system is no longer subject to Section 316(b). See Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information about the sale and decommissioning of Oyster Creek.

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 (i.e., the requirement most likely to support cooling towers). The Ginna, Nine Mile Point Unit 1, and Fitzpatrick power generation facilities have received renewals of their state water discharge permits and cooling towers were not required. These facilities are now engaged in the required analyses to enable the environmental agency to determine the best technology available in the next permit renewal cycles.

Salem

On July 28, 2016, the NJDEP issued a final permit for Salem that did not require the installation of cooling towers and allows Salem to continue to operate utilizing the existing cooling water system with certain required system modifications. However, the permit is being challenged by an environmental organization, and if successful, could result in additional costs for Clean Water Act compliance. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.

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 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, Illinois, Maryland, New Jersey and Pennsylvania and the District of Columbia 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 could become in the future, 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 22 — 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 and PECO’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. BGE, ACE, Pepco and DPL do not have material contingent liabilities relating to MGP sites. The amount to be expended in 2019 for compliance with environmental remediation related to contamination at former MGP sites and other gas purification sites is expected to total $46 million, consisting of $36 million, $6 million and $4 million at ComEd, PECO and BGE respectively. The Utility Registrants also have contingent liabilities for

23

Table of Contents

environmental remediation of non-MGP contaminants (e.g., PCBs). As of December 31, 2018, the Utility Registrants have established appropriate contingent liabilities for environmental remediation requirements.

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

In addition, 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 Note 4 — Regulatory Matters and Note 22 — 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' Consolidated Financial Statements.

Global Climate Change

Exelon has utility and generation assets, and customers, that are and will be further subject to the impacts of climate change. Accordingly, Exelon is engaged in a variety of initiatives to understand and mitigate these impacts, including investments in resiliency, partnering with federal, state and local governments to minimize impacts, and, importantly, advocating for public policy that reduces emissions that cause climate change. Exelon, as a producer of electricity from predominantly low- and zero-carbon generating facilities (such as nuclear, hydroelectric, natural gas, wind and solar photovoltaic), has a relatively small greenhouse gas (GHG) emission profile, or carbon footprint, compared to other domestic generators of electricity (Exelon neither owns nor operates any coal-fueled generating assets). Exelon's natural gas and biomass fired generating plants produce GHG emissions, most notably, CO2. However, Generation's owned-asset emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. As of December 31, 2018, fossil fuel generation represented approximately 29% of Exelon's owned generating capacity, while fossil fuel-fired generation during 2018 represented less than 11% of Exelon's overall generation on a MWh basis. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF6) leakage from electric transmission and distribution operations, refrigerant leakage from chilling and cooling equipment, and fossil fuel combustion in motor vehicles.

Exelon facilities and operations are subject to the global impacts of climate change and Exelon believes its operations could be significantly affected by the physical risks of climate change. 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 additional climate change regulation or legislation at the federal, regional and state levels.

International Climate Change Agreements. 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, and it became effective on November 4, 2016. Under the Paris Agreement, the Parties agreed to try to limit the global average temperature increase to 2°C (3.6°F) above pre-industrial levels. In doing so, Parties developed their own national reduction commitments. The United States submitted a non-binding target of 17% below 2005 emission levels by 2020 and 26% to 28% below 2005 levels by 2025. President Trump has stated his intention to withdraw the U.S. from the Paris Agreement, but no formal action has been initiated.

Federal Climate Change Legislation and Regulation. It is highly unlikely that federal legislation to reduce GHG emissions will be enacted in the near-term. If such legislation is adopted, it would likely increase the value of Exelon's low-carbon fleet even though Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. Continued inaction could negatively impact the value of Exelon's low-carbon fleet.

Under the Obama Administration, the EPA proposed and finalized regulations for fossil fuel-fired power plants, referred to as the Clean Power Plan, which are currently being litigated. Under the Trump Administration, on October

Table of Contents

16, 2017 the EPA proposed to repeal the CPP on the basis that the new Administration believed that the CPP rule went beyond the EPA's authority to establish a best system of emissions reduction (BSER) for existing power plants. Subsequently, on August 31, 2018, EPA proposed its Affordable Clean Energy Rule (ACE), which would replace the CPP with revised emission guidelines based on heat rate improvement measures that could be achieved within the fence line of existing power plants.

Given litigation uncertainty and the absence of a final ACE rule, Exelon and Generation cannot at this time predict the impacts of regulation of existing power plants, or individual state responses to developments related to final resolution of the CPP and ACE regulations, or how developments will impact their future financial statements.

Regional and State Climate Change Legislation and Regulation. A number of states in which Exelon operates have state and regional programs to reduce GHG emissions, including from the power sector. As the nation’s largest generator of carbon-free electricity, our fleet supports these efforts to produce safe, reliable electricity with minimal GHGs. Notably, nine northeast and mid-Atlantic states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island and Vermont) currently participate in the Regional Greenhouse Gas Initiative (RGGI), which is in the process of strengthening its requirements. The program requires most fossil fuel-fired power plants in the region to hold allowances, purchased at auction, for each ton of CO_2 emissions. Non-emitting resources do not have to purchase or hold these allowances.

Many states in which Exelon subsidiaries operate also have state-specific programs to address GHGs, including from power plants. Most notable of these, besides RGGI, are through renewable and other portfolio standards. Additionally, in response to a court decision clarifying the obligations under the Global Warming Solutions Act, the Massachusetts Department of Environmental Protection in 2017 finalized regulations establishing a statewide cap on CO_2 emissions from fossil fuel power plants (Massachusetts remains in RGGI as well). The effect of this new obligation and potential for market illiquidity in the early years represent a risk to Generation’s Massachusetts fossil facilities, including Medway and Mystic. At the same time, the District of Columbia is considering a plan to incorporate the cost of carbon into electricity, via consumption, as well as directly into the cost of transportation and home heating fuels. Details remain to be developed, but the specifics could have implications for Pepco’s operations.

Regardless of whether GHG regulation occurs at the local, state, or federal level, Exelon remains one of the largest, lowest-carbon electric generators in the United States, relying mainly on nuclear, natural gas, hydropower, wind, and solar. The extent that the low-carbon generating fleet will continue to be a competitive advantage for Exelon depends on resolution of the CPP and ACE regulations and associated current or future litigation at the federal level, new or expanded state action on greenhouse gas emissions or direct support of clean energy technologies, including nuclear, as well as potential market reforms that value our fleet’s emission-free attributes.

Renewable and Alternative Energy Portfolio Standards

Thirty-nine states and the District of Columbia, incorporating the vast majority of Exelon operations as well as all utility operations, have adopted some form of RPS requirement. These standards impose varying levels of mandates for procurement of renewable or clean electricity (the definition of which varies by state) and/or energy efficiency. These are generally expressed as a percentage of annual electric load, often increasing by year. Exelon's utilities comply with these various requirements through purchasing qualifying renewables, implementing efficiency programs, acquiring sufficient credits (e.g., RECs), paying an alternative compliance payment, and/or a combination of these compliance alternatives. The Utility Registrants are permitted to recover from retail customers the costs of complying with their state RPS requirements, including the procurement of RECs or other alternative energy resources. New York, Illinois and New Jersey adopted standards targeted at preserving the zero-carbon attributes of certain nuclear-powered generating facilities. Generation owns multiple facilities participating in these programs within these states. Other states in which Generation and our utilities operate are considering similar programs.

See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on renewable portfolio standards.

Table of Contents

Executive Officers of the Registrants as of February 8, 2019
Exelon

Name	Age	Position	Period
Crane, Christopher M.	60	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		Chairman, PHI	2016 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
Cornew, Kenneth W.	53	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
Pramaggiore, Anne R.	60	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2018 - Present
		Chief Executive Officer, ComEd	2012 - 2018
		President, ComEd	2009 - 2018
Dominguez, Joseph	56	Chief Executive Officer, ComEd	2018 - Present
		Executive Vice President, Governmental & Regulatory Affairs and Public Policy, Exelon	2015 - 2018
		Senior Vice President, Governmental & Regulatory Affairs and Public Policy, Exelon	2012 - 2015
Innocenzo, Michael A.	53	President and Chief Executive Officer, PECO	2018 - Present
		Senior Vice President and Chief Operations Officer, PECO	2012 - 2018
Butler, Calvin G.	49	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.	59	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.	65	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
Nigro, Joseph	54	Senior Executive Vice President and Chief Financial Officer, Exelon	2018 - Present
		Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - 2018
Aliabadi, Paymon	56	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013

Table of Contents

Name	Age	Position	Period
Souza, Fabian E.	48	Senior Vice President and Corporate Controller, Exelon	2018 - Present
		Senior Vice President and Deputy Controller, Exelon	2017 - 2018
		Vice President, Controller and Chief Accounting Officer, The AES Corporation	2015 - 2017
		Vice President, Internal Audit and Advisory Services, The AES Corporation	2014 - 2015
		Deputy Corporate Controller, The AES Corporation	2014 - 2014
		Assistant Corporate Controller, Global Controllership, The AES Corporation	2013 - 2014
		Controller, Global Utilities, The AES Corporation	2011 - 2013

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	53	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
Pacilio, Michael J.	58	Executive Vice President and Chief Operating Officer, Exelon Generation	2015 - Present
		President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - 2015
Hanson, Bryan C	53	President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon Generation	2015 - Present
McHugh, James	47	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2018 - Present
		Senior Vice President, Portfolio Management & Strategy, Constellation	2016 - 2018
		Vice President, Portfolio Management, Constellation	2012 - 2016
Barnes, John	55	Senior Vice President, Generation; President, Exelon Power	2018 - Present
		Senior Vice President, Generation, Senior Vice President and Chief Operating Officer, Exelon Power	2012 - 2018
Wright, Bryan P.	52	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
Bauer, Matthew N.	42	Vice President and Controller, Generation	2016 - Present
		Vice President and Controller, BGE	2014 - 2016
		Vice President of Power Finance, Exelon Power	2012 - 2014

Table of Contents

ComEd

Name	Age	Position	Period
Dominguez, Joseph	56	Chief Executive Officer, ComEd	2018 - Present
		Executive Vice President, Governmental & Regulatory Affairs and Public Policy, Exelon	2015 - 2018
		Senior Vice President, Governmental & Regulatory Affairs and Public Policy, Exelon	2012 - 2015
Donnelly, Terence R.	58	President and Chief Operating Officer, ComEd	2018 - Present
		Executive Vice President and Chief Operating Officer, ComEd	2012 - 2018
Jones, Jeanne M.	39	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2018 - Present
		Vice President, Finance, Exelon Nuclear	2014 - 2018
		Director, Finance, Exelon Nuclear	2013 - 2014
Park, Jane	46	Senior Vice President, Customer Operations, ComEd	2018 - Present
		Vice President, Regulatory Policy & Strategy, ComEd	2016 - 2018
		Director, Business Strategy & Technology, ComEd	2014 - 2016
		Chief of Staff to President and Chief Executive Officer, ComEd	2012 - 2014
Gomez, Veronica	49	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	57	Senior Vice President, Governmental and External Affairs, ComEd	2012 - Present
McGuire, Timothy M.	60	Senior Vice President, Distribution Operations, ComEd	2016 - Present
		Vice President, Transmission and Substations, ComEd	2010 - 2016
Kozel, Gerald J.	46	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013

Table of Contents

PECO

Name	Age	Position	Period
Innocenzo, Michael A.	53	President and Chief Executive Officer, PECO	2018 - Present
		Senior Vice President and Chief Operations Officer, PECO	2012 - 2018
McDonald, John	61	Senior Vice President and Chief Operations Officer, PECO	2018 - Present
		Vice President, Integration, Pepco Holdings	2016 - 2018
		Vice President, Technical Services	2006 - 2016
Stefani, Robert J.	44	Senior Vice President, Chief Financial Officer and Treasurer, PECO	2018 - Present
		Vice President, Corporate Development, Exelon	2015 - 2018
		Director, Corporate Development, Exelon	2012 - 2015
Murphy, Elizabeth A.	59	Senior Vice President, Governmental and External Affairs, PECO	2016 - Present
		Vice President, Governmental and External Affairs, PECO	2012 - 2016
Webster Jr., Richard G.	57	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
Feldhake, Lauren	53	Vice President, Customer Operations, PECO	2017 - Present
		Director, Customer Care, PECO	2014 - 2017
		Director, Customer Financial Operations, PECO	2009 - 2014
Diaz Jr., Romulo L.	72	Vice President and General Counsel, PECO	2012 - Present
Bailey, Scott A.	42	Vice President and Controller, PECO	2012 - Present

Table of Contents

BGE

Name	Age	Position	Period
Butler, Calvin G.	49	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.	51	President, BGE	2014 - Present
		Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - 2014
Vahos, David M.	46	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
Núñez, Alexander G.	47	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
Case, Mark D.	57	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
Oddoye, Rodney	42	Vice President, Customer Operations, BGE	2018 - Present
		Director, Northeast Regional Electric Operations, BGE	2016 - 2018
		Director, Financial Operations, BGE	2015 - 2016
		Manager, Distribution Operations, BGE	2013 - 2015
Corse, John	58	Vice President and General Counsel, BGE	2018 - Present
		Associate General Counsel, Exelon	2012 - 2018
Holmes, Andrew W.	50	Vice President and Controller, BGE	2016 - Present
		Director, Generation Accounting, Exelon	2013 - 2016
		Director, Derivatives and Technical Accounting, Exelon	2008 - 2013

Table of Contents

PHI, Pepco, DPL and ACE

Name	Age	Position	Period
Velazquez, David M.	59	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	54	Senior Vice President and Chief Operating Officer, PHI, Pepco, DPL and ACE	2016 - Present
		Senior Vice President, Distribution Operations, ComEd	2010 - 2016
Barnett, Phillip S.	55	Senior Vice President, Chief Financial Officer and Treasurer PHI, Pepco, DPL and ACE	2018 - Present
		Senior Vice President and Chief Financial Officer, PECO	2007 - 2018
		Treasurer, PECO	2012 - 2018
Lavinson, Melissa	49	Senior Vice President, Governmental & External Affairs, PHI, Pepco, DPL and ACE	2018 - Present
		Vice President, Federal Affairs and Policy and Chief Sustainability Officer, PG&E Corporation	2015 - 2018
		Vice President, Federal Affairs, PG&E Corporation	2012 - 2015
Stark, Wendy E.	46	Senior Vice President, Legal and Regulatory Strategy and General Counsel, PHI, Pepco, DPL and ACE	2019 - Present
		Vice President and General Counsel, PHI, Pepco DPL and ACE	2016 - 2018
		Deputy General Counsel, Pepco Holdings, Inc.	2012 - Present
McGowan, Kevin M.	57	Vice President, Regulatory Policy and Strategy, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President, Regulatory Affairs, Pepco Holdings, Inc.	2012 - 2016
Aiken, Robert	52	Vice President and Controller, PHI, Pepco, DPL and ACE	2016 - Present
		Vice President and Controller, Generation	2012 - 2016

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 Risk Officer and the Registrant's Risk Management Committee (RMC), which comprises officers of the Registrant, to identify and evaluate the most significant risks of the Registrant's business and the appropriate steps to manage and mitigate those risks. The Chief 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’ consolidated financial statements 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.

Exelon's consolidated financial statements 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

31

Table of Contents

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 consolidated financial statements 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, (4) the impacts of on-going competition in the retail channel and (5) emerging technologies and business models.
- 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 regulatory business model cost recovery, tax policy, zero emission credit programs 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 (RPS), 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, secure 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, safety and security of its energy delivery systems are fundamental to Exelon's ability to achieve value-added growth for customers, communities and shareholders. Additionally, the operating costs of the Registrants and the opinions of their customers, regulators and shareholders are affected by those companies' ability to maintain the reliability, safety and efficiency of their energy delivery systems.

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 consolidated financial statements (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 exposed to variability of spot and forward market prices in the markets in which it operates.

Table of Contents

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.
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. In addition, in some markets, the supply of electricity could often exceed demand during some hours of the day, resulting in loss of revenue for base-load generating plants such as Exelon's nuclear plants.
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 consolidated financial statements 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 regulated utility growth for the benefit of customers, reduce debt and provide attractive shareholder returns. 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. See Note 8 — Early 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 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 development or applications of technologies related to shale gas production, renewable energy technologies, energy efficiency, distributed generation and energy

33

Table of Contents

storage devices. Such developments could affect the price of energy, levels of customer-owned generation, customer expectations and current business models and 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' consolidated financial statements 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 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 consolidated financial statements 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 and the related asset retirement obligations, their consolidated financial statements 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' consolidated financial statements (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, Canada and Asia. Disruptions in these markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2018, approximately 19%, or $1.8 billion, 19%, or $1.8 billion, and 18%, or $1.7 billion of the Registrants' available credit facilities were with European, Canadian and Asian banks, respectively. The credit facilities include $9.7 billion (including bilateral credit facilities and credit facilities for project

Table of Contents

finance) in aggregate total commitments of which $8.0 billion was available as of December 31, 2018. As of December 31, 2018, there were no borrowings under Generation's bilateral credit facilities. See Note 13 — 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 consolidated financial statements.

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 broad remedies, including rights to foreclose against the project assets and related collateral or to force the Exelon subsidiaries in the project-specific financings to enter into bankruptcy proceedings. The impact of bankruptcy on such arrangements may be a significant assumption in performing impairment assessments of the project assets.

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 remaining sources of liquidity. PJM 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.

Table of Contents

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-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 ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS — Liquidity and Capital Resources — Credit Matters — Market Conditions and Security Ratings for additional 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 consolidated financial statements 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 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 as well as the risk of ineffective hedges. 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 or consolidated financial statements.

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 or effectively address the changes in the wholesale power markets.

Table of Contents

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 impact the Registrants' consolidated financial statements. (All Registrants).

Corporate Tax Reform. On December 22, 2017, President Trump signed into law the TCJA. See Note 14 - Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

While the Registrants' current tax accounting and future expectations are based on management's present understanding of the provisions under the TCJA, further interpretive guidance of the TCJA's provisions could result in further adjustments that could have a material impact to the Registrants' future consolidated financial statements.

The Utility Registrants have made their best estimate regarding the probability and timing of settlements of net regulatory liabilities established pursuant to the TCJA. However, the amount and timing of the settlements may change based on decisions and actions by the rate regulators, which could have a material impact on the Utility Registrants' future consolidated financial statements.

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 appeal 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 Note 1 — Significant Accounting Policies and Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Increases in customer rates, including increases in the cost of purchased power and increases in natural gas prices for the Utility Registrants, 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, cash flows or financial positions (All Registrants).

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 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 affect the Utility Registrants' consolidated financial statements. 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 consolidated financial statements. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information of the Registrants' credit risk.

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 and DPL, 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. 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 adverse effect in the Registrants' consolidated financial statements. Also, the Utility Registrants' cash flows could be adversely affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

The effects of weather could impact the Registrants' consolidated financial statements (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

Table of Contents

at PECO, DPL Delaware and ACE. Due to revenue decoupling, BGE, Pepco and DPL Maryland 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 Future Energy Jobs Act (FEJA), beginning in 2017, customer rates for ComEd are adjusted to eliminate the favorable and unfavorable impacts of weather and customer usage patterns on distribution revenue.

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 in the Utility Registrants' consolidated financial statements. 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. In addition, Exelon and Generation have significant balances related to unamortized energy contracts, as further disclosed in Note 10 — 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, but not limited to, 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 in the Registrants’ consolidated financial statements.

As of December 31, 2018, 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, Note 6 — Property, Plant and Equipment, Note 7 — Impairment of Long-Lived Assets and Intangibles and Note 10 — Intangible Assets of the Combined Notes to the Consolidated Financial Statements for additional information on long-lived asset and goodwill impairments.

Table of Contents

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 in the consolidated financial statements 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 assets and a Registrant could incur substantial costs to fulfill its obligations under these indemnities and such costs could adversely affect a Registrant’s consolidated financial statements.

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 adversely impact that Registrant’s consolidated financial statements. Each of the Utility Registrants has transferred its former generation business to a third party and in each case the transferee may have agreed to assume certain obligations and to indemnify the applicable Utility Registrant for such obligations. In connection with the restructurings under which ComEd, PECO and BGE transferred their generating assets to Generation, Generation assumed certain of ComEd’s, PECO’s and BGE's rights and obligations with respect to their former generation businesses. Further, ComEd, PECO and BGE may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd, PECO or BGE 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, Generation or the transferee of Pepco's, DPL's or ACE’s generation facilities experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, the applicable Utility Registrant could be liable for any existing or future claims, which could impact that Utility Registrant's consolidated financial statements. In addition, the Utility Registrants may have residual liability under certain laws in connection with their former generation facilities.

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 consolidated financial statements. 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, cash flows 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 consolidated financial statements are significantly affected by Generation's sales and purchases of commodities at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon’s and the Utility Registrants' consolidated financial statements are heavily dependent on the ability of the Utility Registrants to recover their costs for the retail purchase and distribution of power and natural gas 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 consolidated financial statements.

39

Table of Contents

State and federal regulatory and legislative developments related to emissions, climate change, tax reform, capacity market mitigation, energy price information, resilience, fuel diversity and RPS could also significantly affect Exelon's and Generation's consolidated financial statements. The Registrants cannot predict when or whether legislative and regulatory proposals could become law or what their effect will be on the Registrants.

Legislative and regulatory efforts in Illinois, New York and New Jersey to preserve the environmental attributes and reliability benefits of zero-emission nuclear-powered generating facilities through zero emission credit programs are subject to legal challenges and, if overturned, could negatively impact Exelon's and Generation's consolidated financial statements and result in the early retirement of certain of Generation's nuclear plants.

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).

Approximately 63% 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 and recognize the value of zero-carbon electricity and resiliency and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competition. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize existing or new generation.

FERC's requirements for market-based rate authority, established in Order 697 and 816 and related subsequent orders, could pose a risk that Generation may no longer satisfy 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 affects Exelon most significantly is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires 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. The primary aim of Dodd-Frank is to regulate the key intermediaries in the swaps market, which entities are swap dealers (SDs), major swap participants (MSPs), or certain other financial entities, but the law also applies to a lesser degree to end-users of swaps. The CFTC's Dodd-Frank regulations generally preserved the ability of end users in the energy industry to hedge their risks using swaps without being subject to mandatory clearing, and many of the other substantive regulations that apply to SDs, MSPs, and other financial entities. Generation manages, and expects to be able to continue to manage, its commercial activity to ensure that it does not have to register as an SD or MSP or other type of covered financial entity.

There are some rulemaking proceedings that have not yet been finalized, in particular, proposed rules on position limits that would apply to both Exchange-traded futures contracts and economically-equivalent over-the-counter swaps. Although the company would incur some costs associated with monitoring and compliance with such rules, it does not expect the rules to have a material impact on its business operations.

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

40

Table of Contents

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. These 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. See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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 22 — 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, subject to refund or disallowed, 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.

Table of Contents

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 rate proceedings have a significant effect on the ability of the Utility Registrants, as applicable, to recover their costs or earn an adequate return and could have a material adverse effect in the Utility Registrants' consolidated financial statements. See Note 4 — Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for additional information regarding rate proceedings.

Federal or additional state RPS and/or energy conservation legislation, along with energy conservation by customers, could negatively affect the consolidated financial statements of Generation and the Utility Registrants (All Registrants).

Changes to current state legislation or the development of Federal legislation that requires the use of clean, renewable and alternate fuel sources 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 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, 2018, 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. 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 Note 1 — Significant Accounting Policies, Note 4 — Regulatory Matters and Note 10 — 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.

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. 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. See ITEM 1. BUSINESS — Global Climate Change and Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding climate change.

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 4 — Regulatory Matters and Note 22 — 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 legislative or regulatory requirements (e.g. disallowances of costs, lower ROEs). The imposition of any of the foregoing could have a material negative impact on the Registrants' business or consolidated financial statements.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could negatively impact their consolidated financial statements (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 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures, result in lost revenue or restrict existing business activities, any of which could have a material adverse effect in the Registrants' consolidated financial statements.

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 consolidated financial statements. Events at nuclear plants owned by others, as well as those owned by Generation, could cause the NRC to initiate such actions.

Table of Contents

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 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 consolidated financial statements. See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information on the SNF obligation.

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, fires resulting from natural causes such as lightning, 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’ consolidated financial statements and their ability to raise capital.

The impact that potential terrorist attacks could have on the industry and on Exelon 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 or interruption of fuel or the supply chain, which could adversely affect the Registrants’ consolidated financial statements and their 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.

44

Table of Contents

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.

In addition, Exelon maintains a level of insurance coverage consistent with industry practices against property, casualty and cybersecurity 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 and higher operating and maintenance costs.

Nuclear fuel quality. The quality of nuclear fuel utilized by Generation could affect the efficiency and costs of Generation’s operations. 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 shutdown 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 nuclear 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 consolidated financial statements. 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 nuclear industry, could be borne by Generation and could have a material adverse effect in Generation’s consolidated financial statements. 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 adversely affect Generation’s consolidated financial statements.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance, $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 $14.1 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 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information of nuclear insurance.

Decommissioning obligation and funding. 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 NDT 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.

Generation recognizes as a liability the present value of the estimated future costs to decommission its nuclear facilities. The estimated liability is based on assumptions in the approach and timing of decommissioning the nuclear facilities, estimation of decommissioning costs and Federal and state regulatory requirements. No assurance can be given that the costs of such decommissioning will not substantially exceed such liability, as facts, circumstances or our estimates may change, including changes in the approach and timing of decommissioning activities, changes in decommissioning costs, changes in Federal or state regulatory requirements on the decommissioning of such facilities, other changes in our estimates or Generation's ability to effectively execute on its planned decommissioning activities.

The performance of capital markets 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 consolidated financial statements could be significantly affected. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. 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 consolidated financial statements 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 15 — 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 Statements of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation. ComEd and PECO have recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability.

If the expected value in the NDT funds for any nuclear unit subject to the regulatory agreements with the ICC is expected to not exceed the total decommissioning obligation for that unit, the accounting to offset decommissioning-

Table of Contents

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 consolidated financial statements could be material. For 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 consolidated financial statements could be material. If the accounting to offset decommissioning-related activities is discontinued, any remaining balances in noncurrent payables to affiliates at Generation and ComEd's or PECO’s noncurrent affiliate receivable from Generation and corresponding regulatory liability may need to be reversed and could have a material impact in 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 on 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 renews 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, could result in increased operating costs or could render the project uneconomic and significantly affect Generation’s consolidated financial statements. 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.

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 consolidated financial statements 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, generation facilities or infrastructure could result in potential liability if such failure results in damage to property or injury to individuals. See ITEM 1. BUSINESS for additional 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 natural causes such as 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' consolidated financial statements could be negatively impacted. Furthermore, if

Table of Contents

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 or third party 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 internal and/or external 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 consolidated financial statements.

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 (Exelon and the Utility 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 Registrants 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 in their and Exelon's consolidated financial statements.

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 increases the potentially unfavorable impacts of such attacks. A security breach of the physical assets or information systems of the Registrants, their competitors, vendors, business partners and 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 result in the 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 the Registrants have been, and will likely continue to be, subjected to physical and cyber-attacks, to date none has directly experienced a material breach or disruption to its 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 or another Registrant 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, loss of revenues, increased costs, operations shutdown, etc., any of which could contribute to the loss of customers and have a negative impact on the business and/or consolidated financial statements. 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

Table of Contents

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 consolidated financial statements.

Failure to attract and retain an appropriately qualified workforce could negatively impact the Registrants’ consolidated financial statements (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 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 consolidated financial statements 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, nuclear advisory or operating services for third parties, 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 and utility of the future initiatives and other non-regulatory mandated 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 in the Utility Registrants' consolidated financial statements.

The Registrants may not realize or achieve the anticipated cost savings through the cost management efforts which could impact the Registrants’ results of operations (All Registrants).

The Registrants’ future financial performance and level of profitability is dependent, in part, on various cost reduction initiatives. The Registrants may encounter challenges in executing these cost reduction initiatives and not achieve the intended cost savings.

ITEM 1B. UNRESOLVED STAFF COMMENTS

All Registrants

None.

Table of Contents

ITEM 2. PROPERTIES

Generation

The following table describes Generation's interests in net electric generating capacity by station at December 31, 2018:

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	2,386	
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	(e)
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,069	
Michigan Wind 2	Midwest	Sanilac Co., MI	50	51	Wind	Base-load	46	(e)(g)
Beebe	Midwest	Gratiot Co., MI	34	51	Wind	Base-load	42	(e)(h)
Michigan Wind 1	Midwest	Huron Co., MI	46	51	Wind	Base-load	35	(e)(g)
Harvest 2	Midwest	Huron Co., MI	33	51	Wind	Base-load	30	(e)(g)
Harvest	Midwest	Huron Co., MI	32	51	Wind	Base-load	27	(e)(g)
Beebe 1B	Midwest	Gratiot Co., MI	21	51	Wind	Base-load	26	(e)(g)
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	20	(e)
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19	(e)
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	9	
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	4	
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3	
CP Windfarm	Midwest	Faribault Co., MN	2	51	Wind	Base-load	2	(e)(g)
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296	(k)
Clinton Battery Storage	Midwest	Blanchester, OH	1		Energy Storage	Peaking	10	
Total Midwest							11,939	
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,317	
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,324	(e)
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,002	(e)
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	895	(e)(f)
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837	(j)
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572	
Criterion	Mid-Atlantic	Oakland, MD	28	51	Wind	Base-load	36	(e)(g)

Table of Contents

Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
Fair Wind	Mid-Atlantic	Garrett County, MD	12		Wind	Base-load	30	
Solar Maryland MC	Mid-Atlantic	Various, MD	40		Solar	Base-load	36	
Fourmile	Mid-Atlantic	Garrett County, MD	16	51	Wind	Base-load	20	(e)(g)
Solar New Jersey 1	Mid-Atlantic	Various, NJ	5		Solar	Base-load	18	
Solar New Jersey 2	Mid-Atlantic	Various, NJ	2		Solar	Base-load	11	
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1	51	Solar	Base-load	8	(e)(g)
Solar Maryland	Mid-Atlantic	Various, MD	11		Solar	Base-load	8	
Solar Maryland 2	Mid-Atlantic	Various, MD	3		Solar	Base-load	8	
Constellation New Energy	Mid-Atlantic	Gaithersburg, MD	1		Solar	Base-load	5	
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5	
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5	51	Solar	Base-load	1	(e)(g)
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	404	
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	(k)
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	116	(k)
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98	
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97	(k)
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	(k)
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56	

Table of Contents

Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
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	Peaking	39	(k)(l)
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39	
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30	
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	1	42.59	Oil	Peaking	16	(e)
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	4	(e)
Bethlehem	Mid-Atlantic	Bethlehem, PA	1		Landfill Gas	Peaking	4	(k)
Eastern	Mid-Atlantic	Bethlehem, PA	3		Landfill Gas	Peaking	4	(k)
Total Mid-Atlantic							10,982	
Whitetail	ERCOT	Webb County, TX	57	51	Wind	Base-load	46	(e)(g)
Sendero	ERCOT	Jim Hogg and Zapata County, TX	39	51	Wind	Base-load	40	(e)(g)
Constellation Solar Texas	Other	Various, TX	11		Solar	Base-load	13	
Colorado Bend II	ERCOT	Wharton, TX	3		Gas	Intermediate	1,088	
Wolf Hollow II	ERCOT	Granbury, TX	3		Gas	Intermediate	1,064	
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395	
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870	
Total ERCOT							3,516	
Solar Massachusetts	New England	Various, MA	10		Solar	Base-load	7	
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	1		Solar	Base-load	1	
Mystic 8, 9	New England	Charlestown, MA	6		Gas	Intermediate	1,417	
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	573	(m)
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	35	(e)
West Medway	New England	West Medway, MA	3		Oil	Peaking	123	

Table of Contents

Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
Framingham	New England	Framingham, MA	3		Oil	Peaking	31	
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9	(m)
Total New England							2,203	
Nine Mile Point	New York	Scriba, NY	2	50.01	Uranium	Base-load	838	(e)(f)
FitzPatrick	New York	Scriba, NY	1		Uranium	Base-load	842	
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288	(e)(f)
Solar New York	New York	Bethlehem, NY	1		Solar	Base-load	3	
Total New York							1,971	
Antelope Valley	Other	Lancaster, CA	1		Solar	Base-load	242	
Bluestem	Other	Beaver County, OK	60	51	Wind	Base-load	101	(e)(g)(h)
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80	
Shooting Star	Other	Kiowa County, KS	65	51	Wind	Base-load	53	(e)(g)
Albany Green Energy	Other	Albany, GA	1	99	Biomass	Base-load	52	(i)
Solar Arizona	Other	Various, AZ	127		Solar	Base-load	46	
Bluegrass Ridge	Other	King City, MO	27	51	Wind	Base-load	29	(e)(g)
California PV Energy 2	Other	Various, CA	89		Solar	Base-load	27	
Conception	Other	Barnard, MO	24	51	Wind	Base-load	26	(e)(g)
Cow Branch	Other	Rock Port, MO	24	51	Wind	Base-load	26	(e)(g)
Solar Arizona 2	Other	Various, AZ	25		Solar	Base-load	23	
California PV Energy	Other	Various, CA	53		Solar	Base-load	21	
Mountain Home	Other	Glenns Ferry, ID	20	51	Wind	Base-load	21	(e)(g)
High Mesa	Other	Elmore Co., ID	19	51	Wind	Base-load	20	(e)(g)
Echo 1	Other	Echo, OR	21	50.49	Wind	Base-load	17	(e)(g)
Sacramento PV Energy	Other	Sacramento, CA	4	51	Solar	Base-load	15	(e)(g)
Cassia	Other	Buhl, ID	14	51	Wind	Base-load	15	(e)(g)
Wildcat	Other	Lovington, NM	13	51	Wind	Base-load	14	(e)(g)
Echo 2	Other	Echo, OR	10	51	Wind	Base-load	10	(e)(g)
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	

Table of Contents

Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10	(e)
Solar Georgia 2	Other	Various, GA	8		Solar	Base-load	10	
Tuana Springs	Other	Hagerman, ID	8	51	Wind	Base-load	9	(e)(g)
Solar Georgia	Other	Various, GA	10		Solar	Base-load	8	
Greensburg	Other	Greensburg, KS	10	51	Wind	Base-load	7	(e)(g)
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6	
Echo 3	Other	Echo, OR	6	50.49	Wind	Base-load	5	(e)(g)
Three Mile Canyon	Other	Boardman, OR	6	51	Wind	Base-load	5	(e)(g)
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5	
California PV Energy 3	Other	Various, CA	10		Solar	Base-load	5	
Mohave Sunrise Solar	Other	Fort Mohave, AZ	1		Solar	Base-load	5	
Denver Airport Solar	Other	Denver, CO	1	51	Solar	Base-load	2	(e)(g)
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	(e)
Total Other							1,852	
Total							32,463	

(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) Net generation capacity is stated at proportionate ownership share.

(f) 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.

(g) Reflects the sale of 49% of EGRP to a third party on July 6, 2017. See Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements for additional information.

(h) EGRP owns 100% of the Class A membership interests and a tax equity investor owns 100% of the Class B membership interests of the entity that owns the Bluestem generating assets.

(i) Generation directly owns a 50% interest in the Albany Green Energy station and an additional 49% through the consolidation of a Variable Interest Entity.

(j) Generation has announced it will permanently cease generation operations at TMI on or about September 30, 2019. See Note 8 — Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

(k) Generation has agreed to retire and cease generation operations at the Gould Street, Fairless Hills, Eastern, Bethlehem, Southeast Chicago, Notch Cliff, Riverside (unit 8), Westport and Pennsbury units on or before June 1, 2020.

(l) Generation plans to retire and cease generation operation at Riverside (unit 7) on or about March 14, 2019.

(m) Generation plans to retire and cease generation operation at the Mystic 7 and Mystic Jet units on or about June 1, 2022.

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.

Table of Contents

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 in 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 high voltage electric transmission lines owned and in service at December 31, 2018 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,716
138,000	2,209

ComEd's electric distribution system includes 35,398 circuit miles of overhead lines and 32,010 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 in 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.

Table of Contents

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2018 were as follows:

Voltage (Volts)	Circuit Miles	
500,000	188	[(a)]
230,000	549	
138,000	135	
69,000	181	

(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.

PECO's electric distribution system includes 12,957 circuit miles of overhead lines and 9,367 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2018:

	Pipeline Miles
Transmission	9
Distribution	6,912
Service piping	6,377
Total	13,298

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 160 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 105 mmcf and a peaking capability of 25 mmcf/day. In addition, PECO owns 30 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 in 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.

Table of Contents

Transmission and Distribution

BGE's high voltage electric transmission lines owned and in service at December 31, 2018 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	358
138,000	55
115,000	706

BGE's electric distribution system includes 9,191 circuit miles of overhead lines and 17,295 circuit miles of underground lines.

Gas

The following table sets forth BGE's natural gas pipeline miles at December 31, 2018:

	Pipeline Miles
Transmission	161
Distribution	7,348
Service piping	6,305
Total	13,814

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 in 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.

Table of Contents

Transmission and Distribution

Pepco’s high voltage electric transmission lines owned and in service at December 31, 2018 were as follows:

Voltage (Volts)	Circuit Miles
500,000	142
230,000	767
138,000	61
115,000	38

Pepco’s electric distribution system includes approximately 4,127 circuit miles of overhead lines and 7,039 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.

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 in 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, 2018 were as follows:

Voltage (Volts)	Circuit Miles
500,000	16
230,000	471
138,000	586
69,000	569

DPL’s electric distribution system includes approximately 6,031 circuit miles of overhead lines and 6,298 circuit miles of underground lines. DPL also owns and operates a distribution system control center in New Castle, Delaware.

Table of Contents

Gas

The following table sets forth DPL's natural gas pipeline miles at December 31, 2018:

	Pipeline Miles
Transmission [(a)]	8
Distribution	2,065
Service piping	1,398
Total	3,471

(a) DPL has a 10% undivided interest in approximately 8 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 250 mmcf and an emergency sendout capability of 36 mmcf/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 mmcf/day.

First Mortgage and Insurance

The principal properties of DPL 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 in 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, 2018 were as follows:

Voltage (Volts)	Circuit Miles
500,000	—
230,000	221
138,000	239
69,000	663

ACE's electric distribution system includes approximately 7,378 circuit miles of overhead lines and 2,927 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.

Table of Contents

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 in 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.

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 4 — Regulatory Matters and Note 22 — 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.

Table of Contents

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 (trading symbol: EXC). As of January 31, 2019, there were 969,745,933 shares of common stock outstanding and approximately 99,857 record holders of common stock.

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 2014 through 2018.

This performance chart assumes:

- $100 invested on December 31, 2013 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.

Table of Contents

Value of Investment at December 31,

	2013	2014	2015	2016	2017	2018
Exelon Corporation	$100	$140.61	$109.44	$145.34	$167.22	$197.86
S&P 500	$100	$113.68	$115.24	$129.02	$157.17	$150.27
S&P Utilities	$100	$128.98	$122.73	$142.72	$160.00	$166.57

Generation

As of January 31, 2019, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2019, there were 127,021,331 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, 2019, in addition to Exelon, there were 294 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2019, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

Table of Contents

BGE
As of January 31, 2019, 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, 2019, Exelon indirectly held the entire membership interest in PHI.
Pepco
As of January 31, 2019, 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, 2019, 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, 2019, 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.
ComEd has 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 restrictions established by the MDPSC that prohibit BGE 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. No such event has occurred.
Pepco is subject to certain dividend restrictions established by settlements approved in Maryland and the District of Columbia. Pepco is prohibited from paying a dividend on its common shares if (a) after the dividend payment, Pepco's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the MDPSC and DCPSC or (b) Pepco’s senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.
DPL is subject to certain dividend restrictions established by settlements approved in Delaware and Maryland. DPL is prohibited from paying a dividend on its common shares if (a) after the dividend payment, DPL's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the DPSC and MDPSC or (b) DPL’s

Table of Contents

senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. No such event has occurred.

ACE is subject to certain dividend restrictions established by settlements approved in New Jersey. ACE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, ACE's equity ratio would be 48% as equity levels are calculated under the ratemaking precedents of the NJBPU or (b) ACE's senior unsecured credit rating is rated by one of the three major credit rating agencies below investment grade. ACE is also subject to a dividend restriction which requires ACE to 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%. No such events have occurred.

Exelon’s Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

At December 31, 2018, Exelon had retained earnings of $14,766 million, including Generation’s undistributed earnings of $3,724 million, ComEd’s retained earnings of $1,337 million consisting of retained earnings appropriated for future dividends of $2,976 million, partially offset by $1,639 million of unappropriated accumulated deficits, PECO’s retained earnings of $1,242 million, BGE’s retained earnings of $1,640 million, and PHI's undistributed earnings of $62 million.

The following table sets forth Exelon’s quarterly cash dividends per share paid during 2018 and 2017:

	2018				2017			
(per share)	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
Exelon	0.345	0.345	0.345	0.345	0.328	0.328	0.328	0.328

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

	2018				2017			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$313	$ 311	$ 189	$ 188	$165	$ 164	$ 166	$ 164
ComEd	114	116	115	114	106	105	106	105
PECO	6	7	6	287	72	72	72	72
BGE	52	52	53	52	50	49	50	49
PHI	94	123	38	71	44	136	62	69
Pepco	41	78	25	25	—	75	28	30
DPL	38	18	4	36	30	28	24	30
ACE	13	27	10	9	15	31	12	10

First Quarter 2019 Dividend

On February 5, 2019, the Exelon Board of Directors declared a first quarter 2019 regular quarterly dividend of $0.3625 per share on Exelon’s common stock payable on March 8, 2019, to shareholders of record of Exelon at the end of the day on February 20, 2019.

Table of Contents

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)	2018	2017[c, d]	2016[a, c, d]	2015[c]	2014[b,c]
Statement of Operations data:					
Operating revenues	$35,985	$33,565	$31,366	$29,447	$27,429
Operating income	3,898	4,395	3,212	4,554	3,210
Net income	2,084	3,876	1,196	2,250	1,820
Net income attributable to common shareholders	2,010	3,786	1,121	2,269	1,623
Earnings per average common share (diluted):					
Net income	$2.07	$3.99	$1.21	$2.54	$1.88
Dividends per common share	$1.38	$1.31	$1.26	$1.24	$1.24

(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) Amounts have been recasted to reflect the Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost guidance adopted as of January 1, 2018. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

(d) Amounts for 2017 and 2016 have been recasted to reflect the Revenue from Contracts with Customers guidance adopted as of January 1, 2018. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information. The 2015 and 2014 balances are not recasted for this guidance and are not comparative.

	December 31,				
(In millions)	2018	2017[a]	2016[a]	2015[a]	2014[a]
Balance Sheet data:					
Current assets	$13,360	$11,896	$12,451	$15,334	$11,853
Property, plant and equipment, net	76,707	74,202	71,555	57,439	52,170
Total assets	119,666	116,770	114,952	95,384	86,416
Current liabilities	11,404	10,798	13,463	9,118	8,762
Long-term debt, including long-term debt to financing trusts	34,465	32,565	32,216	24,286	19,853
Shareholders' equity	30,764	29,896	25,860	25,793	22,608

(a) Amounts for 2017 and 2016 have been recasted to reflect the Revenue from Contracts with Customers guidance adopted as of January 1, 2018. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information. The 2015 and 2014 balances are not recasted for this guidance and are not comparative.

Table of Contents

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)	2018	2017[b]	2016[b]	2015	2014[a]
Statement of Operations data:					
Operating revenues	$20,437	$18,500	$17,757	$19,135	$17,393
Operating income	975	947	820	2,275	1,176
Net income	443	2,798	550	1,340	1,019

____

(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) Amounts for 2017 and 2016 have been recasted to reflect the Revenue from Contracts with Customers guidance adopted as of January 1, 2018. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information. The 2015 and 2014 balances are not recasted for this guidance and are not comparative.

	December 31,				
(In millions)	2018	2017[a]	2016[a]	2015	2014
Balance Sheet data:					
Current assets	$8,433	$6,882	$6,567	$6,342	$7,311
Property, plant and equipment, net	23,981	24,906	25,585	25,843	23,028
Total assets	47,556	48,457	47,022	46,529	44,951
Current liabilities	5,769	4,191	5,689	4,933	4,459
Long-term debt, including long-term debt to affiliates	7,887	8,644	8,124	8,869	7,582
Member's equity	13,204	13,669	11,505	11,635	12,718

(a) Amounts for 2017 and 2016 have been recasted to reflect the Revenue from Contracts with Customers guidance adopted as of January 1, 2018. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information. The 2015 and 2014 balances are not recasted for this guidance and are not comparative.

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.

	For the Years Ended December 31,				
(In millions)	2018	2017	2016	2015	2014
Statement of Operations data:					
Operating revenues	$5,882	$5,536	$5,254	$4,905	$4,564
Operating income	1,146	1,323	1,205	1,017	980
Net income	664	567	378	426	408

Table of Contents

(In millions)	December 31, 2018	2017	2016	2015	2014
Balance Sheet data:					
Current assets	$1,570	$1,364	$1,554	$1,518	$1,723
Property, plant and equipment, net	22,058	20,723	19,335	17,502	15,793
Total assets	31,213	29,726	28,335	26,532	25,358
Current liabilities	1,925	2,294	2,938	2,766	1,923
Long-term debt, including long-term debt to financing trusts	8,006	6,966	6,813	6,049	5,870
Shareholders' equity	10,247	9,542	8,725	8,243	7,907

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)	For the Years Ended December 31, 2018	2017	2016	2015	2014
Statement of Operations data:					
Operating revenues	$3,038	$2,870	$2,994	$3,032	$3,094
Operating income	587	655	702	630	572
Net income	460	434	438	378	352

(In millions)	December 31, 2018	2017	2016	2015	2014
Balance Sheet data:					
Current assets	$782	$ 822	$ 757	$ 842	$645
Property, plant and equipment, net	8,610	8,053	7,565	7,141	6,801
Total assets	10,642	10,170	10,831	10,367	9,860
Current liabilities	809	1,267	727	944	653
Long-term debt, including long-term debt to financing trusts	3,268	2,587	2,764	2,464	2,416
Shareholder's equity	3,820	3,577	3,415	3,236	3,121

Table of Contents

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.

	For the Years Ended December 31,				
(In millions)	2018	2017	2016	2015	2014
Statement of Operations data:					
Operating revenues	$3,169	$3,176	$3,233	$3,135	$3,165
Operating income	474	614	550	558	439
Net income	313	307	294	288	211

	December 31,				
(In millions)	2018	2017	2016	2015	2014
Balance Sheet data:					
Current assets	$786	$811	$842	$845	$951
Property, plant and equipment, net	8,243	7,602	7,040	6,597	6,204
Total assets	9,716	9,104	8,704	8,295	8,056
Current liabilities	774	760	707	1,134	794
Long-term debt, including long-term debt to financing trusts	2,876	2,577	2,533	1,732	2,109
Shareholder's equity	3,354	3,141	2,848	2,687	2,563

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		
	For the Years Ended December 31,		March 24 to December 31	January 1 to March 23,	For the Years Ended December 31,	
(In millions)	2018	2017	2016	2016	2015	2014
Statement of Operations data[(a)]:						
Operating revenues	$4,805	$4,679	$ 3,643	$1,153	$4,935	$4,808
Operating income	650	769	93	105	673	605
Net income (loss) from continuing operations	398	362	(61)	19	318	242
Net income (loss)	398	362	(61)	19	327	242

Table of Contents

	Successor			Predecessor
	December 31,			December 31,
(In millions)	2018	2017	2016	2015
Balance Sheet data[(a)]:				
Current assets	$1,533	$1,551	$1,838	$ 1,474
Property, plant and equipment, net	13,446	12,498	11,598	10,864
Total assets	21,984	21,247	21,025	16,188
Current liabilities	1,592	1,931	2,284	2,327
Long-term debt	6,134	5,478	5,645	4,823
Preferred Stock	—	—	—	183
Member’s equity/Shareholders' equity	9,282	8,825	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.

	For the Years Ended December 31,				
(In millions)	2018	2017	2016	2015	2014
Statement of Operations data[(a)]:					
Operating revenues	$2,239	$2,158	$2,186	$2,129	$2,055
Operating income	320	399	174	385	349
Net income	210	205	42	187	171

	December 31,			
(In millions)	2018	2017	2016	2015
Balance Sheet data[(a)]:				
Current assets	$760	$710	$684	$726
Property, plant and equipment, net	6,460	6,001	5,571	5,162
Total assets	8,299	7,832	7,335	6,908
Current liabilities	628	550	596	455
Long-term debt	2,704	2,521	2,333	2,340
Shareholder's equity	2,740	2,533	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.

Table of Contents

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)	2018	2017	2016	2015	2014
Statement of Operations data[a]:					
Operating revenues	$1,332	$1,300	$1,277	$1,302	$1,282
Operating income	190	229	50	165	207
Net income (loss)	120	121	(9)	76	104

	December 31,			
(In millions)	2018	2017	2016	2015
Balance Sheet data[a]:				
Current assets	$336	$325	$370	$388
Property, plant and equipment, net	3,821	3,579	3,273	3,070
Total assets	4,588	4,357	4,153	3,969
Current liabilities	375	547	381	564
Long-term debt	1,403	1,217	1,221	1,061
Shareholder's equity	1,509	1,335	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.

	For the Years Ended December 31,				
(In millions)	2018	2017	2016	2015	2014
Statement of Operations data[a]:					
Operating revenues	$1,236	$1,186	$1,257	$1,295	$1,210
Operating income	149	157	7	134	137
Net income (loss)	75	77	(42)	40	46

Table of Contents

	December 31,			
(In millions)	2018	2017	2016	2015
Balance Sheet data[(a)]:				
Current assets	$240	$258	$399	$546
Property, plant and equipment, net	2,966	2,706	2,521	2,322
Total assets	3,699	3,445	3,457	$3,387
Current liabilities	422	619	320	$297
Long-term debt	1,170	840	1,120	1,153
Shareholder's equity	1,126	1,043	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.

Table of Contents

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

Exelon

Executive Overview

Exelon is a utility services holding company engaged in the generation, delivery, and marketing of energy through Generation and the energy distribution and transmission businesses through ComEd, PECO, BGE, Pepco, DPL and ACE.

Exelon has twelve reportable segments consisting of Generation’s six reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions), ComEd, PECO, BGE, Pepco, DPL and ACE. During the first quarter of 2019, due to a change in economics in our New England region, Generation is changing the way that information is reviewed by the CODM. The New England region will no longer be regularly reviewed as a separate region by the CODM nor will it be presented separately in any external information presented to third parties. Information for the New England region will be reviewed by the CODM as part of Other Power Regions. As a result, beginning in the first quarter of 2019, Generation will disclose five reportable segments consisting of Mid-Atlantic, Midwest, New York, ERCOT and Other Power Regions. See Note 1 - Significant Accounting Policies and Note 24 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's principal subsidiaries and reportable segments.

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. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, accounting, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. Additionally, the results of Exelon’s corporate operations include interest costs and income from various investment and financing activities.

Exelon’s consolidated financial information includes the results of its eight separate operating subsidiary registrants, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management’s Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Table of Contents

Financial Results of Operations

GAAP Results of Operations. The following table sets forth Exelon's GAAP consolidated Net Income attributable to common shareholders by Registrant for the year ended December 31, 2018 compared to the same period in 2017 and December 31, 2017 compared to the same period in 2016. For additional information regarding the financial results for the years ended December 31, 2018, 2017 and 2016 see the discussions of Results of Operations by Registrant.

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Exelon	$2,010	$3,786	$ (1,776)	$1,121	$ 2,665
Generation	370	2,710	(2,340)	483	2,227
ComEd	664	567	97	378	189
PECO	460	434	26	438	(4)
BGE	313	307	6	286	21
Pepco	210	205	5	42	163
DPL	120	121	(1)	(9)	130
ACE	75	77	(2)	(42)	119
Other[(b)]	(195)	(594)	399	(422)	(172)

	Successor For the Years Ended December 31,		Favorable (unfavorable) 2018 vs. 2017 variance	March 24 to December 31,	Predecessor January 1 to March 23,
	2018	2017		2016	2016
PHI[(a)]	$398	$362	$ 36	$ (61)	$ 19

(a) Includes the consolidated results of Pepco, DPL and ACE.

(b) Primarily includes eliminating and consolidating adjustments, Exelon's corporate operations, shared service entities and other financing and investing activities.

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income attributable to common shareholders decreased by $1,776 million and diluted earnings per average common share decreased to $2.07 in 2018 from $3.99 in 2017 primarily due to:

- Impacts associated with the one-time remeasurement of deferred income taxes in 2017 as a result of the TCJA;
- Net unrealized losses on NDT funds in 2018 compared to net gains in 2017;
- Lower realized energy prices;
- Accelerated depreciation and amortization due to the decision to early retire the Oyster Creek and TMI nuclear facilities;
- The gain associated with the FitzPatrick acquisition in 2017;
- Decrease in reserves for uncertain tax positions in 2017 related to the deductibility of certain merger commitments associated with the 2012 Constellation and 2016 PHI acquisitions;
- Increased mark-to-market losses;
- The gain recorded upon deconsolidation of EGTP's net liabilities in 2017;
- The absence of EGTP earnings resulting from its deconsolidation in the fourth quarter of 2017;

Table of Contents

- Long-lived asset impairments of certain merchant wind assets in West Texas; and
- Increased storm costs at PECO and BGE.

The decreases were partially offset by;

- The impact of the New York and Illinois ZEC revenue (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017);
- Long-lived asset impairments primarily related to the EGTP assets held for sale in 2017;
- Increased capacity prices;
- The impact of lower federal income tax rate as a result of the TCJA at Generation;
- Net realized gains on NDT funds;
- The gain on the settlement of a long-term gas supply agreement;
- Decreased nuclear outage days;
- Increased electric distribution and energy efficiency formula rate earnings at ComEd;
- Regulatory rate increases at PECO, BGE and PHI;
- The impact of favorable weather at PECO, DPL and ACE; and
- The absences of a 2017 impairment of certain transmission-related income tax regulatory assets at ComEd, BGE and PHI.

The decrease in diluted earnings per share was also due to the increase in Exelon’s average diluted shares outstanding as a result of the June 2017 common stock issuance.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income attributable to common shareholders increased by $2,665 million and diluted earnings per average common share increased to $3.99 in 2017 from $1.21 in 2016 primarily due to:

- Impacts associated with the one-time remeasurement of deferred income taxes as a result of the TCJA;
- The gain associated with the FitzPatrick acquisition;
- Accelerated depreciation and amortization due to the decision to early retire the TMI nuclear facility in 2017 compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities;
- Higher net unrealized and realized gains on NDT funds;
- The impact of the New York ZEC revenue;
- The gain recorded upon deconsolidation of EGTP's net liabilities;
- Increased capacity prices;
- Decreased nuclear outage days;
- Decrease in reserves for uncertain tax positions in 2017 related to the deductibility of certain merger commitments associated with the 2012 Constellation and 2016 PHI acquisitions compared to costs incurred as part of the settlement orders approving the PHI acquisition and a charge related to a 2012 CEG merger commitment in 2016;
- Increased electric distribution and transmission formula rate earnings at ComEd;

Table of Contents

- Regulatory rate increases at BGE and PHI; and
- Penalties and associated interest expense as a result of a tax court decision on Exelon's like-kind exchange position in 2016.

The increases were partially offset by;

- Long-lived asset impairments primarily related to the EGTP assets held for sale;
- Lower realized energy prices;
- The conclusion of the Ginna Reliability Support Services Agreement;
- Increased costs related to the acquisition of the FitzPatrick nuclear facility;
- Increased mark-to-market losses;
- The impact of unfavorable weather at ComEd, PECO, DPL and ACE; and
- The impairment of certain transmission-related income tax regulatory assets at ComEd, BGE and PHI.

The net increase in diluted earnings per share from the items listed above was partially offset by the impact of the increase in Exelon’s average diluted shares outstanding as a result of the June 2017 common stock issuance.

Adjusted (non-GAAP) Operating Earnings. 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, 2018 as compared to 2017 and 2016:

Table of Contents

	For the Years Ended December 31,					
	2018		2017		2016	
(All amounts after tax; in millions, except per share amounts)		Earnings per Diluted Share		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$2,010	$ 2.07	$3,786	$ 3.99	$1,121	$ 1.21
Mark-to-Market Impact of Economic Hedging Activities[(a)] (net of taxes of $89, $68 and $18, respectively)	252	0.26	107	0.11	24	0.03
Unrealized Losses (Gains) Related to NDT Funds[(b)] (net of taxes of $289, $286 and $112, respectively)	337	0.35	(318)	(0.34)	(118)	(0.13)
Amortization of Commodity Contract Intangibles[(c)] (net of taxes of $0, $22 and $22, respectively)	—	—	34	0.04	35	0.04
Merger and Integration Costs[(d)] (net of taxes of $2, $25 and $50, respectively)	3	—	40	0.04	114	0.12
Merger Commitments[(e)] (net of taxes of $0, $137 and $126, respectively)	—	—	(137)	(0.14)	437	0.47
Long-Lived Asset Impairments[(f)] (net of taxes of $13, $204 and $68, respectively)	35	0.04	321	0.34	103	0.11
Plant Retirements and Divestitures[(g)] (net of taxes of $181, $134 and $273, respectively)	512	0.53	207	0.22	432	0.47
Cost Management Program[(h)] (net of taxes of $16, $21 and $21, respectively)	48	0.05	34	0.04	34	0.04
Annual Asset Retirement Obligation Update[(i)] (net of taxes of $7, $1 and $13, respectively)	20	0.02	(2)	—	(75)	(0.08)
Vacation Policy Change[(j)] (net of taxes of $0, $21 and $0, respectively)	—	—	(33)	(0.03)	—	—
Change in Environmental Liabilities (net of taxes of $0, $17 and $0, respectively)	(1)	—	27	0.03	—	—
Bargain Purchase Gain[(k)] (net of taxes of $0, $0 and $0, respectively)	—	—	(233)	(0.25)	—	—
Gain on Deconsolidation of Business[(l)] (net of taxes of $0, $83 and $0, respectively)	—	—	(130)	(0.14)	—	—
Gain on Contract Settlement[(m)] (net of taxes of $20, $0 and $0, respectively)	(55)	(0.06)	—	—	—	—
Like-Kind Exchange Tax Position[(n)] (net of taxes of $0, $66 and $61, respectively)	—	—	(26)	(0.03)	199	0.21
Curtailment of Generation Growth and Development Activities[(o)] (net of taxes of $0, $0 and $35, respectively)	—	—	—	—	57	0.06
Reassessment of Deferred Income Taxes[(p)] (entire amount represents tax expense)	(22)	(0.02)	(1,299)	(1.37)	10	0.01
Tax Settlements[(q)] (net of taxes of $0, $1 and $0, respectively)	—	—	(5)	(0.01)	—	—
Noncontrolling Interests[(r)] (net of taxes of $24, $24 and $9, respectively)	(113)	(0.12)	114	0.12	102	0.11
Adjusted (non-GAAP) Operating Earnings	$3,026	$ 3.12	$2,487	$ 2.62	$2,475	$ 2.67

76

Table of Contents

____

Note:
Unless otherwise noted, the income tax impact of each reconciling item between GAAP Net Income and Adjusted (non-GAAP) Operating Earnings is based on the marginal statutory federal and state income tax rates for each Registrant, taking into account whether the income or expense item is taxable or deductible, respectively, in whole or in part. For all items except the unrealized gains and losses related to NDT funds, the marginal statutory income tax rates for 2018, 2017 and 2016 ranged from 26.0 percent to 29.0 percent, 39.0 percent to 41.0 percent and 39.0 percent to 41.0 percent, respectively. Under IRS regulations, NDT fund returns are taxed at different rates for investments if they are in qualified or non-qualified funds. The effective tax rates for the unrealized gains and losses related to NDT funds were 46.2 percent, 47.4 percent and 48.7 percent for the years ended December 31, 2018, 2017 and 2016, respectively.

(a) Reflects the impact of net losses on economic hedging activities. See Note 12 - Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information related to hedging activities.

(b) Reflects the impact of net unrealized gains and losses on Generation’s NDT funds for Non-Regulatory and Regulatory Agreement Units. The impacts of the Regulatory Agreement Units, including the associated income taxes, are contractually eliminated, resulting in no earnings impact.

(c) Represents the non-cash amortization of intangible assets, net, primarily related to commodity contracts recorded at fair value related to, in 2016, the Integrys and ConEdison Solutions acquisitions, and in 2017, the ConEdison Solutions and FitzPatrick acquisitions.

(d) Reflects certain costs associated with mergers and acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities. In 2016 and 2017, reflects costs related to the PHI and FitzPatrick acquisitions, partially offset in 2016 at ComEd, and in 2017, at PHI, by the anticipated recovery of previously incurred PHI acquisition costs. In 2018, reflects costs related to the PHI acquisition. See Note 5 - Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Represents costs incurred as part of the settlement orders approving the PHI acquisition, and in 2016, a charge related to a 2012 CEG merger commitment, and in 2017, primarily a decrease in reserves for uncertain tax positions related to the deductibility of certain merger commitments associated with the 2012 CEG and 2016 PHI acquisitions.

(f) In 2016, primarily reflects the impairment of upstream assets and certain wind projects at Generation. In 2017, primarily reflects the impairment of the EGTP assets held for sale and PHI District of Columbia sponsorship intangible asset. In 2018, primarily reflects the impairment of certain wind projects at Generation.

(g) In 2016, primarily reflects accelerated depreciation and amortization expenses through December 2016 and construction work in progress impairments associated with Generation’s previous decision to early retire the Clinton and Quad Cities nuclear facilities, partially offset by a gain associated with Generation’s sale of the New Boston generating site. In 2017, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's previous decision to early retire the TMI nuclear facility. In 2018, primarily reflects accelerated depreciation and amortization expenses and one-time charges associated with Generation's decision to early retire the Oyster Creek nuclear facility, a charge associated with a remeasurement of the Oyster Creek ARO and accelerated depreciation and amortization expenses associated with the previous decision to early retire the TMI nuclear facility, partially offset by a gain associated with Generation's sale of its electrical contracting business.

(h) Primarily represents severance and reorganization costs related to a cost management program.

(i) For Pepco, reflects an increase related to asbestos identified at its Buzzard Point property.

(j) Represents the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.

(k) Represents the excess of the fair value of assets and liabilities acquired over the purchase price for the FitzPatrick acquisition.

(l)

Represents the gain recorded upon deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing.

(m) Represents the gain on the settlement of a long-term gas supply agreement at Generation.

(n) Represents in 2016 the recognition of a penalty and associated interest expense as a result of a tax court decision on Exelon's like-kind exchange tax position, and in 2017, adjustments to income tax, penalties and interest expenses as a result of the finalization of the IRS tax computation related to Exelon's like-kind exchange tax position.

(o) Reflects the one-time recognition for a loss on sale of assets and 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.

(p) Reflects in 2016 the non-cash impact of the remeasurement of deferred income taxes as a result of changes in forecasted apportionment related to the PHI acquisition. In 2017, one-time non-cash impacts associated with remeasurements of deferred income taxes as a result of the TCJA (including impacts on pension obligations contained within Other), changes in the Illinois and District of Columbia statutory tax rates and changes in forecasted apportionment. In 2018, reflects an adjustment to the remeasurement of deferred income taxes as a result of the TCJA and changes in forecasted apportionment.

(q) Reflects benefits related to the favorable settlement of certain income tax positions related to PHI's unregulated business interests.

(r) Represents elimination from Generation's results of the noncontrolling interests related to certain exclusion items, primarily related to the impact of unrealized gains and losses on NDT funds at CENG.

Table of Contents

Significant 2018 Transactions and Recent Developments

Regulatory Implications of the Tax Cuts and Jobs Act (TCJA)

The Utility Registrants have made filings with their respective State regulators to begin passing back to customers the ongoing annual tax savings resulting from the TCJA. The amounts being proposed to be passed back to customers reflect the annual benefit of lower income tax rates and the settlement of a portion of deferred income tax regulatory liabilities established upon enactment of the TCJA. The Utility Registrants have identified over $675 million in ongoing annual savings to be returned to customers related to TCJA from their distribution utility operations. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Utility Rates and Base Rate Proceedings

The Utility Registrants file base 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.

Table of Contents

The following tables show the Utility Registrants' completed and pending distribution base rate case proceedings in 2018. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on other regulatory proceedings.

Completed Utility Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase (Decrease)	Approved Revenue Requirement Increase (Decrease)	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois (Electric)	April 16, 2018	$ (23) [a]	$ (24) [a]	8.69 %	December 4, 2018	January 1, 2019
PECO - Pennsylvania (Electric)	March 29, 2018	$ 82 [a]	$ 25 [a]	N/A	December 20, 2018	January 1, 2019
BGE - Maryland (Natural Gas)	June 8, 2018 (amended August 24, 2018 and October 12, 2018)	$ 61	$ 43	9.8 %	January 4, 2019	January 4, 2019
Pepco - Maryland (Electric)	January 2, 2018 (amended February 5, 2018)	$ 3 [a]	$ (15) [a]	9.5 %	May 31, 2018	June 1, 2018
Pepco - District of Columbia (Electric)	December 19, 2017 (amended February 9, 2018)	$ 66	$ (24) [a]	9.525 %	August 9, 2018	August 13, 2018
DPL - Maryland (Electric)	July 14, 2017 (amended November 16, 2017)	$ 19	$ 13	9.5 %	February 9, 2018	February 9, 2018
DPL - Delaware (Electric)	August 17, 2017 (amended February 9, 2018)	$ 12 [a]	$ (7) [a]	9.7 %	August 21, 2018	March 17, 2018
DPL - Delaware (Natural Gas)	August 17, 2017 (amended February 9, 2018)	$ 4 [a]	$ (4) [a]	9.7 %	November 8, 2018	March 17, 2018

____

(a) Includes the annual ongoing TCJA tax savings further discussed above.

79

Table of Contents

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase	Requested ROE	Expected Approval Timing
ACE - New Jersey (Electric)	August 21, 2018 (amended November 19, 2018)	$ 122 [(a)]	10.1 %	Third quarter of 2019
Pepco - Maryland (Electric)	January 15, 2019	$ 30	10.3 %	Third quarter of 2019

____

(a) Includes the annual ongoing TCJA tax savings further discussed above.

Transmission Formula Rate

The following total (decreases)/increases were included in ComEd's, BGE's, Pepco's, DPL's and ACE's 2018 annual electric transmission formula rate updates.

Registrant	Initial Revenue Requirement (Decrease) Increase[(b)]	Annual Reconciliation Increase/(Decrease)	Total Revenue Requirement (Decrease) Increase)	Allowed Return on Rate Base[(d)]	Allowed ROE[(e)]
ComEd[(a)]	$ (44)	$ 18	$ (26)	8.32 %	11.50 %
BGE[(a)]	10	4	26 [(c)]	7.61 %	10.50 %
Pepco	6	2	8	7.82 %	10.50 %
DPL	14	13	27	7.29 %	10.50 %
ACE[(a)]	4	(4)	—	8.02 %	10.50 %

____

(a) The time period for any challenges to the annual transmission formula rate update flings expired with no challenges submitted.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

(c) BGE's transmission revenue requirement includes a FERC approved dedicated facilities charge of $12 million to recover the costs of providing transmission service to specifically designated load by BGE.

(d) Represents the weighted average debt and equity return on transmission rate bases.

(e) As part of the FERC-approved settlement of ComEd’s 2007 transmission rate case, the rate of return on common equity is 11.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO.

PECO Transmission Formula Rate

On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO’s transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO’s annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On

June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included

Table of Contents

an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

Illinois ZEC Procurement

Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event. Generation executed the required ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue, with compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. During the year ended December 31, 2018, Generation recognized revenue of $373 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

Early Plant Retirements

On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at Oyster Creek at the end of its current operating cycle and permanently ceased generation operations in September 2018. Because of the decision to early retire Oyster Creek in 2018, Exelon and Generation recognized certain one-time charges in the first quarter of 2018 related to a materials and supplies inventory reserve adjustment, employee-related costs and construction work-in-progress impairments, among other items.

On July 31, 2018, Generation entered into an agreement with Holtec International and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC, for the sale and decommissioning of Oyster Creek. See Note 5 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

On May 30, 2017, Generation announced it will permanently cease generation operations at Three Mile Island Generating Station (TMI) on or about September 30, 2019. The plant is currently committed to operate through May 2019. As a result of the early nuclear plant retirement decisions at Oyster Creek and TMI, Exelon and Generation will also recognize annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. The following table summarizes the actual incremental non-cash expense item incurred in 2018 and the estimated amount of incremental non-cash expense items expected to be incurred in 2019 due to the early retirement decisions.

	Actual	Projected[(a)]
Income statement expense (pre-tax)	2018	2019
Depreciation and Amortization[(b)]		
Accelerated depreciation[(c)]	$ 539	$ 230
Accelerated nuclear fuel amortization	57	5
Operating and maintenance[(d)]	32	5
Total	$ 628	$ 240

(a) Actual results may differ based on incremental future capital additions, actual units of production for nuclear fuel amortization, future revised ARO assumptions, etc.

(b) Reflects incremental accelerated depreciation and amortization for TMI and Oyster Creek for the year ended December 31, 2018. The Oyster Creek year-to-date amounts are from February 2, 2018 through September 17, 2018.

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

(d) Primarily includes materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments.

In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants including Salem, of which Generation owns a 42.59% ownership interest. PSEG is the operator of Salem and also has the decision making authority to retire Salem.

On May 23, 2018, New Jersey enacted legislation that established a ZEC program, similar to that in Illinois and New York, that will provide compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. The NJBPU must complete its processes for determining eligibility for,

Table of Contents

and participation in, the ZEC program by April 18, 2019. On December 19, 2018, PSEG submitted its application for Salem. Assuming the successful implementation of the New Jersey ZEC program and the selection of Salem as one of the qualifying facilities, the New Jersey ZEC program has the potential to mitigate the heightened risk of earlier retirement for Salem. See Note 4 — Regulatory Matters and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

Generation’s Dresden, Byron, and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level.

On March 29, 2018, based on ISO-NE capacity auction results for the 2021 - 2022 planning year in which Mystic Unit 9 did not clear, Generation notified grid operator ISO-NE of its plans to early retire its Mystic Generating Station assets absent regulatory reforms on June 1, 2022, at the end of the current capacity commitment for Mystic Units 7 and 8. As a result of these developments, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group during the first quarter of 2018 and no impairment charge was required.

The ISO-NE announced that it would take a three-step approach to fuel security.

- First, on May 1, 2018, ISO-NE made a filing with FERC requesting waiver of certain tariff provisions to allow it to retain Mystic Units 8 and 9 for fuel security for the 2022 - 2024 planning years. FERC denied the waiver request on procedural grounds on July 2, 2018 and ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address fuel security concerns and (ii) make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns.
- Second, in accordance with FERC's July 2, 2018 order, on August 31, 2018, ISO-NE made a filing with FERC proposing short-term tariff changes to permit it to retain a resource for fuel security reliability reasons, which FERC accepted on December 3, 2018.
- Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE’s January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic Units 8 and 9, cannot recover future operating costs including the cost of procuring fuel. In its July 2, 2018 order, FERC ordered ISO-NE to make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. In January 2019, ISO-NE indicated that it intends to seek an extension of the deadline for this filing to November 15, 2019.

On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 and 9 for the period between June 1, 2022 - May 31, 2024. On December 20, 2018, FERC issued an order accepting the cost of service agreement reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the Everett Marine Terminal. On January 4, 2019, Generation notified ISO–NE that it will participate in the Forward Capacity Market auction for the 2022 – 2023 capacity commitment period. In addition, on January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings of the December 20, 2018 order. The request for rehearing does not alter Generation's commitment to participate in the Forward Capacity Auction for the 2022–2023 capacity commitment period. Further developments such as the failure of ISO-NE to adopt long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset group, which could be material. See Note 7 — Impairment of Long-Lived Assets and Intangibles and Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements for additional information.

Pension Plan Merger

Effective January 1, 2019, Exelon is merging the Exelon Corporation Cash Balance Pension Plan (CBPP) into the Exelon Corporation Retirement Program (ECRP). The merging of the plans is not changing the benefits offered to the plan participants and, thus, has no impact on Exelon's pension obligation. However, beginning in 2019, actuarial losses and gains related to the CBPP and ECRP will be amortized over participants' average remaining service period of the merged ECRP rather than each individual plan, which will lower Exelon's 2019 pre-tax pension cost by approximately $90 million.

Winter Storm-Related Costs

During March 2018 there were powerful nor'easter storms that brought a mix of heavy snow, ice and high sustained winds and gusts to the region that interrupted electric service delivery to customers in PECO's, BGE's, Pepco's, DPL's and ACE's service territories. Restoration efforts included significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies, which resulted in incremental operating and maintenance expense and incremental capital expenditures in the first quarter of 2018 for PECO, BGE, PHI, Pepco, DPL and ACE. In addition, PHI, Pepco, DPL and ACE recorded regulatory assets for amounts that are probable of recovery through customer rates. The impacts recorded by the Registrants for the twelve months ended December 31, 2018 are presented below:

	(in millions)		
	Customer Outages	Incremental Operating & Maintenance	Incremental Capital Expenditures
Exelon	1,727,000	$ 88 (b)	$ 85
PECO	750,000	53	34
BGE	425,000	31	16
PHI(a)	552,000	4 (b)	35
Pepco	182,000	2 (b)	4
DPL	138,000	2 (b)	4
ACE	232,000	— (b)	27

(a) PHI reflects the consolidated customer outages, incremental operating & maintenance and incremental capital expenditures of Pepco, DPL and ACE.

(b) Excludes amounts that were deferred and recognized as regulatory assets at Exelon, PHI, Pepco, DPL and ACE of $27 million, $27 million, $5 million, $1 million and $21 million, respectively.

Westinghouse Electric Company LLC Bankruptcy

On March 29, 2017, Westinghouse Electric Company LLC (Westinghouse) and its affiliated debtors filed petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Southern District of New York. On January 4, 2018, Westinghouse announced its agreement to be purchased by an affiliate of Brookfield Business Partners, LLC (Brookfield) for approximately $4.6 billion. On March 28, 2018, the Bankruptcy Court entered an Order confirming the Debtor's Second Amended Joint Plan of Reorganization which provides for the transaction with Brookfield. The transaction closed on August 1, 2018. Exelon had contracts with Westinghouse primarily related to Generation's purchase of nuclear fuel, as well as a variety of services and equipment purchases associated with the operation and maintenance of nuclear generating stations. In conjunction with the confirmation hearing, Exelon had filed a reservation of rights regarding reorganizing Westinghouse's assumption of all Exelon contracts. Exelon reached an agreement with Brookfield, and all Exelon contracts were assumed by Brookfield on the closing date.

Exelon's Strategy and Outlook for 2019 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:

- The Utility Registrants provide a foundation for steadily growing earnings, which translates to a stable currency in our stock.

Table of Contents

- Generation's competitive businesses provide free cash flow to invest primarily in 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 Utility Registrants 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 Utility Registrants 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, the Utility Registrants anticipate making significant future investments in smart grid technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Generation's competitive businesses create value for customers by providing innovative energy solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide 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 approved a dividend policy providing a raise of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 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. One key issue is ensuring the ability to properly value nuclear generation assets in the market, solutions to which Exelon is actively pursuing in a variety of jurisdictions and venues. See ITEM 1A. RISK FACTORS for additional information regarding market and financial factors.

Continually optimizing the cost structure is a key component of Exelon's financial strategy. In August 2015, Exelon announced a cost management program focused on cost savings of approximately $400 million at BSC and Generation, which was fully realized in 2018. Approximately 75% of the savings were related to Generation, with the remaining amount related to the Utility Registrants. In November 2017, Exelon announced a commitment for an additional $250 million of cost savings, primarily at Generation, to be achieved by 2020. In November 2018, Exelon announced the elimination of an approximately additional $200 million of annual ongoing costs, through initiatives primarily at Generation and BSC, by 2021. Approximately $150 million is expected to be related to Generation, with the remaining amount related to the Utility Registrants. These actions are in response to the continuing economic challenges confronting all parts of Exelon's business and industry, necessitating continued focus on cost management through enhanced efficiency and productivity.

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 enhances Exelon's regulated growth to provide stable cash flows, earnings accretion, and dividend support. Additionally, the Utility Registrants anticipate investing approximately $29 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart grid technology, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $16 billion by the end of 2023. 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 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Investments and infrastructure development and enhancement programs.

Competitive Energy Businesses. Generation continually assesses the optimal structure and composition of its generation assets as well as explores wholesale and retail opportunities within the power and gas sectors. Generation's long-term growth strategy is to ensure appropriate valuation of its generation assets, in part through public policy efforts, identify and capitalize on opportunities that provide generation to load matching as a means to provide stable earnings, and identify emerging technologies where strategic investments provide the option for significant future growth or influence in market development.

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, $0.3 billion, $0.3 billion and $0.3 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 and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

For additional information regarding the Registrants' liquidity for the year ended December 31, 2018, see Liquidity and Capital Resources discussion below.

Project Financing

Project financing is used to help mitigate risk of specific generating assets. Project financing is based upon a nonrecourse financial structure, in which project debt is paid back from the cash generated by the specific asset or portfolio of assets. 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 debt financing covenants, there could be a requirement to accelerate repayment of the associated debt or other project-related borrowings earlier than the stated maturity dates. In these instances, if such repayment was not satisfied, or restructured, 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 lives. Additionally, project finance has credit facilities of $0.2 billion as of December 31, 2018. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on nonrecourse debt.

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

Table of Contents

of operations, cash flows and financial positions. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information 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).

FERC Inquiry on Resiliency

On August 23, 2017, the DOE staff released its report on the reliability of the electric grid. One aspect of the wide-ranging report is the DOE's recognition that the electricity markets do not currently value the resiliency provided by base-load generation, such as nuclear plants. On September 28, 2017, the DOE issued a Notice of Proposed Rulemaking (NOPR) that would entitle certain eligible resilient generating units (i.e., those located in organized markets, with a 90-day supply of fuel on site, not already subject to state cost of service regulation and satisfying certain other requirements) to recover fully allocated costs and earn a fair return on equity on their investment. On January 8, 2018, FERC issued an order terminating the rulemaking docket that it initiated to address the proposed rule in the DOE NOPR, concluding the proposed rule did not sufficiently demonstrate there is a resiliency issue and that it proposed a remedy that did not appear to be just, reasonable and nondiscriminatory as required under the Federal Power Act. At the same time, FERC initiated a new proceeding to consider resiliency challenges to the bulk power system and evaluate whether additional FERC action to address resiliency would be appropriate. FERC directed each RTO and ISO to respond within 60 days to 24 specific questions about how they assess and mitigate threats to resiliency. Thereafter, interested parties submitted reply comments on May 9, 2018, and a few parties submitted further replies. Exelon has been and will continue to be an active participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Complaints and PJM Filing at FERC Seeking to Mitigate ZEC Programs

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 effectively remove the revenues it receives through a 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 gas-fired resources.

On January 9, 2017, 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. A similar complaint also against PJM was filed at FERC on May 31, 2018. These complaints generally allege that the relevant MOPR should be expanded to also apply to existing resources including those receiving ZEC compensation under the New York CES and Illinois ZES programs. Exelon 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 programs that have generally not been subject to a MOPR. However, if successful, for Generation's facilities in PJM and NYISO that are currently receiving ZEC compensation (Quad Cities, Ginna, Fitzpatrick and Nine Mile Point), an expanded MOPR could require exclusion of ZEC compensation when bidding into future capacity auctions such that these facilities would have an increased risk of not clearing in future capacity auctions and thus no longer receiving capacity revenues during the respective ZEC programs. 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 same risk would also exist for the Salem facility if Salem is selected as an eligible facility under the New Jersey ZEC program.

Separately, PJM submitted two proposed alternative capacity market reforms in April 2018 for FERC's consideration. PJM argued that either alternative will resolve any conflict between state policy support for certain resources and the need to ensure reasonable prices for non-supported resources. The first alternative was to implement a twice-run capacity clearing mechanism (known as the repricing proposal) and, if not acceptable to FERC, a second

86

alternative that would expand the existing MOPR to both new and existing generating resources, subject to certain exemptions (known as MOPREx).

In June 2018, FERC issued an order rejecting both of PJM's proposed alternatives, finding both to be unjust and unreasonable. In the same order, FERC also addressed one of the MOPR complaints involving PJM and concluded based on that complaint and PJM's filing that PJM's existing tariff allows resources receiving out-of-market support to affect capacity prices in a manner that will cause unjust and unreasonable and unduly discriminatory rates in PJM regardless of the intent motivating the support. FERC suggested that modifying two elements of PJM's existing tariff could produce a just and reasonable replacement and asked for initial comments on its proposal by August 28, 2018, later extended to October 2, 2018. First, FERC found that an expansion of the current MOPR mechanism to cover all existing generating resources, regardless of resource type, including those receiving either ZEC or REC compensation, could protect the capacity markets from unwanted price suppression. Second, FERC preliminarily found that a modified version of PJM's existing Fixed Resource Requirement (FRR) option could enable state subsidized resources and a corresponding amount of load to be removed from the capacity market, thereby alleviating their price suppressive effects on capacity clearing prices. Under this alternative, state supported generating resources would potentially be compensated through mechanisms other than through PJM's existing market mechanism. FERC established March 21, 2016 as the refund effective date and also allowed PJM to delay its next capacity auction from May 2019 to August 2019 to allow parties time to develop and file proposals in the FERC proceeding, FERC time to determine the appropriate solution and PJM time to implement FERC's solution. On October 2, 2018, Exelon, along with several ratepayer advocates, environmental organizations and other nuclear generators, submitted shared principles supporting a workable new FRR mechanism (as suggested by FERC) and detailing how such a mechanism should be implemented. Exelon also submitted individual comments covering matters not addressed in the shared principles. FERC has not yet issued a decision on the second MOPR complaint involving PJM or the MOPR complaint involving NYISO. It is too early to predict the final outcome of each of these proceedings or their potential financial impact, if any, on Exelon or Generation.

Section 232 Uranium Petition

On January 16, 2018, two Canadian-owned uranium mining companies with operations in the U.S. jointly submitted a petition to the U.S. Department of Commerce (DOC) seeking relief under Section 232 of the Trade Expansion Act of 1962 (as amended) from imports of uranium products, alleging that these imports threaten national security (the Petition). The Trade Expansion Act of 1962 (the Act) was promulgated by Congress to protect essential national security industries whose survival is threatened by imports. As such, the Act authorizes the Secretary of Commerce (the Secretary) to conduct investigations to evaluate the effects of imports of any item on the national security of the U.S. The Petition alleges that the loss of a viable U.S. uranium mining industry would have a significant detrimental impact on the national, energy, and economic security of the U.S. and the ability of the country to sustain an independent nuclear fuel cycle.

On July 18, 2018, the Secretary announced that the DOC has initiated an investigation in response to the petition. The Secretary has 270 days to prepare and submit a report to President Trump, who then has 90 days to act on the Secretary's recommendations. Exelon and Generation cannot currently predict the outcome of this investigation. The relief sought by the petitioners would require U.S. nuclear reactors to purchase at least 25% of their uranium needs from domestic mines over the next 10 years, although the DOC will make an independent determination regarding an appropriate remedy should it find that imports impair national security. It is reasonably possible that if this petition is successful the resulting increase in nuclear fuel costs in future periods could have a material, unfavorable impact on Exelon's and Generation's financial statements.

Potential DOE Order Pursuant to Defense Production Act and Federal Power Act

The DOE is considering an Order directing ISOs, for 24 months, to purchase electric energy or generation capacity from a designated list of coal and nuclear generation facilities. Based on a draft memorandum, the Order would be pursuant to DOE's authorities under the Defense Production Act and Federal Power Act, and would forestall any further actions towards retiring, decommissioning, or deactivating coal and nuclear facilities during the term of the Order. The Order would emphasize the importance of grid resiliency, in addition to grid reliability, noting that fuel security and diversity are critical components of resiliency. The DOE recognizes that the underlying economic and regulatory issues are complex and will take time resolve. The Order's 24-month duration would enable DOE to conduct additional analyses to gain a detailed understanding of location-specific vulnerabilities in U.S. energy delivery systems, while preserving certain generation facilities. Exelon has been and will continue to be an active

Table of Contents

participant in these proceedings but cannot predict the final outcome or its potential financial impact, if any, on Exelon or Generation.

Energy Demand

Modest economic growth partially offset by energy efficiency initiatives is resulting in relatively flat load growth in electricity for the Utility Registrants. ComEd, BGE, Pepco, DPL and ACE are projecting load volumes to increase (decrease) by (0.2)%, (0.1)%, 0.3%, (0.3)% and (1.5)%, respectively, in 2019 compared to 2018. PECO is projecting load volumes to be flat in 2019 compared to 2018.

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. 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, second, third and fourth quarter 2018 dividends of $0.3450 per share each on Exelon's common stock, and the first quarter 2019 dividends declared was $0.3625. The dividends for the first, second, third and fourth quarter 2018 were paid on March 9, 2018, June 8, 2018, September 10, 2018 and December 10, 2018, respectively. The first quarter 2019 dividend is payable on March 8, 2019.

Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 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 2019 and 2020. 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, 2018, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92%, 56%-59% and 32%-35% for 2019, 2020, and 2021 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 62% of Generation's uranium concentrate requirements from 2019 through 2023 are supplied by three producers. In the event of non-performance by these

88

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 positions.

The Utility Registrants mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Environmental Legislative and Regulatory Developments

Exelon was actively involved in the Obama Administration’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 fossil-fueled electric generating units, as set forth in the discussion below. These regulations have had a disproportionate adverse impact on coal-fired power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and have resulted in the retirement of older, marginal facilities. Due to its low emission generation portfolio, Generation has not been significantly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil fuel plants.

Through the issuance of a series of Executive Orders (EO), President Trump has initiated review of a number of EPA and other regulations issued during the Obama Administration, with the expectation that the Administration will seek repeal or significant revision of these rules. Under these EOs, each executive agency is required to evaluate existing regulations and make recommendations regarding repeal, replacement, or modification. The Administration’s actions are intended to result in less stringent compliance requirements under air, water, and waste regulations. The exact nature, extent, and timing of the regulatory changes are unknown, as well as the ultimate impact on Exelon’s and its subsidiaries results of operations and cash flows.

In particular, the Administration has targeted existing EPA regulations for repeal, including notably the Clean Power Plan, as well as revoking many Executive Orders, reports, and guidance issued by the Obama Administration on the topic of climate change or the regulation of greenhouse gases. The Executive Order also disbanded the Interagency Working Group that developed the social cost of carbon used in rulemakings, and withdrew all technical support documents supporting the calculation. Other regulations that have been specifically identified for review are the Clean Water Act rule relating to jurisdictional waters of the U.S., the Steam Electric Effluent Guidelines relating to waste water discharges from coal-fired power plants, and the 2015 National Ambient Air Quality Standard (NAAQS) for ozone. The review of final rules could extend over several years as formal notice and comment rulemaking process proceeds.

Air Quality

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. On April 27, 2017, the D.C. Circuit granted EPA’s motion to hold the litigation in abeyance, pending EPA’s review of the MATS rule pursuant to President Trump’s EO discussed above. Following EPA’s review and determination of its course of action for the MATS rule, the parties will have 30 days to file motions on future proceedings. Notwithstanding the Court’s order to hold the litigation in abeyance, 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. On December 28, 2018, the EPA proposed to revoke the "appropriate and necessary" finding underpinning the MATS rule. While the proposal would leave in place the rule, it would leave it vulnerable to future legal challenge.

Table of Contents

Clean Power Plan. On April 28, 2017, the D.C. Circuit Court issued orders in separate litigation related to the EPA's actions under the Clean Power Plan (CPP) to amend Clean Air Act Section 111(d) regulation of existing fossil-fired electric generating units and Section 111(b) regulation of new fossil-fired electric generating units. In both cases, the Court has determined to hold the litigation in abeyance pending a determination whether the rule should be remanded to the EPA. On October 10, 2017, EPA issued a proposed rule to repeal the CPP in its entirety, based on a proposed change in the Agency's legal interpretation of Clean Air Act Section 111(d) regarding actions that the Agency can consider when establishing the Best System of Emission Reduction ("BSER") for existing power plants. Under the proposed interpretation, the Agency exceeded its authority under the Clean Air Act by regulating beyond individual sources of GHG emissions. Subsequently, on August 31, 2018, EPA proposed its Affordable Clean Energy Rule (ACE), which would replace the CPP with revised emission guidelines based on heat rate improvement measures that could be achieved within the fence line of existing power plants.

2015 Ozone National Ambient Air Quality Standards (NAAQS). On April 11, 2017, the D.C. Circuit ordered that the consolidated 2015 ozone NAAQS litigation be held in abeyance pending EPA's further review of the 2015 Rule. EPA did not meet the October 1, 2017 deadline to promulgate initial designations for areas in attainment or non-attainment of the standard. A number of states and environmental organizations have notified the EPA of their intent to file suit to compel EPA to issue the designations.

Climate Change. Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. In the absence of Federal legislation, the EPA is moving forward with the regulation of GHG emissions under the Clean Air Act. In addition, there have been recent developments in the international regulation of GHG emissions pursuant to the United Nations Framework Convention on Climate Change ("UNFCCC" or "Convention"). See ITEM 1. BUSINESS, "Global Climate Change" for additional information.

Water Quality

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 recent changes to the regulations. For Generation, those facilities are Calvert Cliffs, Clinton, Dresden, Eddystone, Fairless Hills, FitzPatrick, Ginna, Gould Street, Handley, Mystic 7, Nine Mile Point Unit 1, Peach Bottom, Quad Cities, and Salem. See ITEM 1. BUSINESS, "Water Quality" for additional information.

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 accruals consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations.

See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information related to environmental matters, including the impact of environmental regulation.

Other Legislative and Regulatory Developments

Delaware Distribution System Investment Charge

On June 14, 2018, the Governor of Delaware signed new Distribution System Investment Charge (DSIC) legislation, which establishes a system improvement charge that provides a mechanism to recover infrastructure investments, allowing for gradual rate increases and limiting frequency of distribution base rate cases. On November 30, 2018, DPL filed its first electric and gas filing in Delaware with the new rates being put into effect on January 1, 2019. This legislation supports needed infrastructure investment and allows for more timely recovery of those investments, however Exelon, PHI and DPL do not expect a material impact on the financial statements.

Table of Contents

Pennsylvania Alternative Ratemaking

On June 28, 2018, the Governor of Pennsylvania signed Act 58 of 2018, which authorizes the PAPUC to review and approve utility-proposed alternative rate mechanisms, including options such as decoupling mechanisms, formula rates, multi-year rate plans, and performance based rates. Exelon and PECO cannot predict the outcome or the potential financial impact, if any, on Exelon or PECO.

District of Columbia Clean Energy Bill

On December 18, 2018, the Council of the District of Columbia passed the Clean Energy District of Columbia Omnibus Amendment Act of 2018 (the Act), which was subsequently signed by the Mayor of the District of Columbia on January 18, 2019. The Act is expected to take effect in February 2019 following the expiration of a 30-day review process by the U.S. House of Representatives. Among other things, the Act would increase electric load by requiring all public buses, taxis and other specified fleets to be solely zero-emissions vehicles by 2045. The Act would also clarify that, under certain circumstances, the gas and electric utilities may offer and receive cost recovery including a return on investment on capital and related costs for energy efficiency programs in the District of Columbia.

Employees

In January 2017, an election was held at BGE which resulted in union representation for approximately 1,284 employees. BGE and IBEW Local 410 are negotiating an initial agreement which could result in some modifications to wages, hours and other terms and conditions of employment. Negotiations have been productive and continue. No agreement has been finalized to date and management cannot predict the outcome of such negotiations. Negotiations that began in 2017 for a first collective bargaining agreement with a small unit of employees represented by Local 501 of Operating Engineers at Exelon's Hyperion Solutions facility are complete and the new CBA will expire in 2021. During 2017, Generation finalized CBAs with the Security Officer unions at LaSalle, Limerick and Quad Cities, which all will expire in 2020 and Dresden expiring in 2021. Additionally, during 2017, Generation acquired and combined two CBAs at Fitzpatrick into one CBA covering both craft and security employees, which will expire in 2023. Generation also successfully finalized the CBA with the IBEW union at TMI, which will expire in 2022. During 2018, Generation finalized its CBA with the Security Officer's union at Braidwood, which will expire in 2021. Additionally, ACE successfully finalized two contract renewals with the IBEW Local 210, and the new BAs will expire in 2023. As previously reported, there was an organizing effort over approximately 18 ACE control room System Operators. While an election was held with an outcome favorable to Local 210, collective bargaining over this small segment of employees will not commence until the issue of whether the System Operators are NLRA statutory supervisors is determined, and that matter is currently before the NLRB. Furthermore, there was an organizing effort at PECO over approximately 150 Working Foreperson positions. In October 2018, the Working Foreperson group overwhelmingly rejected unionization in an election held by the NLRB. Lastly, on December 27, 2018 a representation petition was filed by the LEOSU Union seeking to represent security officers at Clinton Power station who are currently represented by SEIU Local 1. The current collective bargaining agreement between Exelon Nuclear Security and the SEIU Local 1 has been extended, so that the matter between the two rival labor organizations can be resolved. No election or determination has been held and it is anticipated that this matter will be resolved in 2019.

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 amounts of assets and liabilities reported in the financial statements. 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 information 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 $10.0 billion at December 31, 2018. 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.

91

Table of Contents

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 NDT 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 following methodologies and significant estimates and assumptions:

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. 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.

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. The assumed decommissioning scenarios include the following three alternatives: (1) DECON which assumes decommissioning activities begin shortly after the cessation of operation, (2) Shortened SAFSTOR generally has a 30-year delay prior to onset of decommissioning activities, and (3) SAFSTOR which assumes the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated generally within 60 years after cessation of operations. In each decommissioning scenario, 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

Table of Contents

and develop the necessary infrastructure for long-term SNF storage. For additional information regarding the estimated date that DOE will begin accepting SNF, see Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.

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. Generation initially recognizes an ARO at fair value and subsequently adjusts it for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions. The ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. 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. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFR, the obligation would increase from approximately \$10.0 billion to approximately \$10.1 billion.

The following table illustrates 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 (dollars in millions):

Change in the CARFR applied to the annual ARO update	Increase (Decrease) to ARO at December 31, 2018
2017 CARFR rather than the 2018 CARFR	\$ 50
2018 CARFR increased by 50 basis points	(100)
2018 CARFR decreased by 50 basis points	130

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 to ARO at December 31, 2018
Cost escalation studies	
Uniform increase in escalation rates of 50 basis points	\$ 1,530
Probabilistic cash flow models	
Increase the estimated costs to decommission the nuclear plants by 10 percent	650
Increase the likelihood of the DECON scenario by 10 percent and decrease the likelihood of the SAFSTOR scenario by 10 percent[a]	410
Shorten each unit's probability weighted operating life assumption by 10 percent[b]	720
Extend the estimated date for DOE acceptance of SNF to 2035	90

(a) Excludes any sites in which management has committed to a specific decommissioning approach.
(b) Excludes any retired site or sites for which an early plant retirement has been announced.

See Note 1 — Significant Accounting Policies, Note 8 — Early Plant Retirements and Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for nuclear decommissioning obligations.

Goodwill (Exelon, ComEd and PHI)

As of December 31, 2018, Exelon's $6.7 billion carrying amount of goodwill consists of $2.6 billion at ComEd, $4 billion at PHI and immaterial amounts at Generation and DPL. 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. 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. ComEd has a single operating segment and reporting unit. PHI’s operating segments and reporting units are Pepco, DPL and ACE. See Note 24 — Segment Information of the Combined Notes to Consolidated Financial Statements for additional information. Exelon's and ComEd’s goodwill has been assigned entirely to the ComEd reporting unit. Exelon's and PHI’s goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $2.1 billion, $1.4 billion and $0.5 billion, respectively. See Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. As part of the qualitative assessments, Exelon, ComEd and PHI evaluate, among other things, management's best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer EBITDA multiples, and the passing margin from their last quantitative assessments performed.

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.

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. While the annual assessments indicated no impairments, certain assumptions used in the assessment are highly sensitive to changes. Adverse regulatory actions or changes in significant assumptions could potentially result in future impairments of Exelon’s, ComEd's or PHI’s goodwill, which could be material. Based on the results of the last annual quantitative goodwill tests performed as of November 1, 2016 and November 1, 2018 for ComEd and PHI, respectively, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30%, 30%, 20% and 30%, respectively, for ComEd and PHI to fail the first step of their respective impairment tests.

See Note 1 — Significant Accounting Policies and Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon, Generation and PHI)

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 the purchase price exceeds the estimated net fair value or as a bargain purchase gain on the income statement if the purchase price is less than 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, could significantly impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. The allocation of the purchase price may be modified up to one year after the acquisition date as more information is obtained about the fair value of assets acquired and liabilities assumed. If the transaction is determined to be an asset acquisition the purchase price is allocated to the assets acquired and the liabilities assumed and no goodwill or bargain purchase gain would be recorded. See Note 5 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

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

94

Table of Contents

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired and the electricity contracts Exelon has acquired as part of the PHI merger. The initial amount recorded represents the fair value of the contracts at the time of acquisition. At Exelon and PHI, offsetting regulatory assets or liabilities were also recorded for those energy contract costs that are probable of recovery or refund through customer rates. 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 of the unamortized energy contract assets and liabilities is recorded through purchased power and fuel expense or operating revenues, depending on the nature of the underlying contract. See Note 4 — Regulatory Matters, Note 5 — Mergers, Acquisitions and Dispositions and Note 10 — Intangible Assets of the Combined Notes to Consolidated Financial Statements for additional information.

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, an asset remaining idle for more than a short period of time, specific regulatory disallowance, advances in technology, plans to dispose of a long-lived asset significantly before the end of its useful life, and financial distress of a third party for assets contracted with them on a long-term basis, 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 and purchases 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 impact in 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). For such assets the financial viability of the third party, including the impact of bankruptcy on the contract, may be a significant assumption in the assessment.

On a quarterly basis, Generation assesses its long-lived assets or 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. 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.

See Note 7 — Impairment of Long-Lived Assets and Intangibles 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 group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for heterogeneous assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the group. The estimation of asset useful lives requires management judgment, supported by formal depreciation studies of historical asset retirement experience. Depreciation studies are generally 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 customer rates, unless the depreciation rates reflected in customer rates do not align with management's judgment as to an appropriate estimated useful life or have not been updated on a timely basis. Depreciation expense and customer rates for ComEd, BGE, Pepco, DPL and ACE includes an estimate of the future costs of dismantling and removing plant from service upon retirement. See Note 4 - Regulatory Matters of the Combined Notes to the Consolidated Financial Statements for information regarding regulatory liabilities and assets recorded by ComEd, BGE, Pepco, DPL and ACE related to removal costs.

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. 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 8 — Early Plant Retirements of the Combined Notes to the Consolidated Financial Statements for additional information.

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 current employees. 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 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.

Expected Rate of Return on Plan Assets. In determining the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectation regarding future long-term capital market performance, weighted by Exelon's target asset class allocations. 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

96

Table of Contents

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.

Discount Rate. At December 31, 2018 and 2017, 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.

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’s mortality assumption is supported by an actuarial experience study of Exelon's plan participants and utilizes the IRS's RP-2000 base table and the Scale BB 2-Dimensional improvement scale with long-term improvements of 0.75%.

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):

	Actual Assumption					
Actuarial Assumption	Pension	OPEB	Change in Assumption	Pension	OPEB	Total
Change in 2018 cost:						
Discount rate [(a)]	3.62%	3.61%	0.5%	$ (51)	$ (17)	$ (68)
	3.62%	3.61%	(0.5)%	62	21	83
EROA	7.00%	6.60%	0.5%	(90)	(13)	(103)
	7.00%	6.60%	(0.5)%	89	13	102
Change in benefit obligation at December 31, 2018:						
Discount rate [(a)]	4.31%	4.30%	0.5%	(1,180)	(246)	(1,426)
	4.31%	4.30%	(0.5)%	1,371	284	1,655

(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 utilizes a liability-driven investment strategy for its pension asset portfolio. The sensitivities shown above do not reflect the offsetting impact that changes in discount rates may have on pension asset returns.

See Note 16 — 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.

Regulatory Accounting (Exelon and Utility Registrants)

For their regulated electric and gas operations, Exelon and the Utility Registrants reflect the effects of cost-based rate regulation in their financial statements, which is required 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) a reasonable expectation that rates designed to recover costs can be charged to and collected 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) revenue or gains 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. If it is concluded in a future period that a separable portion of operations no longer meets the criteria discussed above, 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.

Table of Contents

The following table illustrates the gains (losses) that could result from the elimination of regulatory assets and liabilities and charges against OCI (dollars in millions before taxes) related to deferred costs associated with Exelon's pension and other postretirement benefit plans that are recorded as regulatory assets in Exelon's Consolidated Balance Sheets:

December 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Gain (loss)	$744	$4,743	$ 55	$694	$(853)	$(84)	$375	$(6)
Charge against OCI[(a)]	$3,754	$—	$ —	$—	$—	$—	$—	$—

(a) Exelon's charge against OCI (before taxes) consists of up to $2.4 billion, $529 million, $157 million, $413 million, $208 million and $105 million related to ComEd's, BGE's, PHI's, Pepco's, DPL's and ACE's respective portions of the deferred costs associated with Exelon's pension and other postretirement benefit plans. Exelon also has a net regulatory liability of $(47) million (before taxes) related to PECO’s portion of the deferred costs associated with Exelon’s other postretirement benefit plans that would result in an increase in OCI if reversed.

See Note 4 — 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. 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 in their consolidated financial statements could be material.

Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ICC-approved electric distribution and energy efficiency formula rates for ComEd, and FERC transmission formula rate tariffs for the Utility Registrants.

Accounting for Derivative Instruments (All Registrants)

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange risk and interest rate risk related to ongoing business operations. The Registrants’ derivative activities are in accordance with Exelon’s Risk Management Policy (RMP). See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether a contract qualifies as a derivative 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 quantities. Changes in management’s assessment of contracts and the liquidity of their markets, and changes in authoritative guidance, could result in previously excluded contracts becoming in scope to new authoritative guidance.

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. Derivatives entered into for economic hedging and for proprietary trading purposes are recorded at fair value through earnings. For economic hedges that are not designated for hedge accounting for the Utility Registrants, changes in the fair value each period are generally recorded with a corresponding offsetting regulatory asset or liability given likelihood of recovering the associated costs through customer rates.

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 by Generation as normal purchases and normal sales transactions, which are thus not required to be

98

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 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 that 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 the contract 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 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 the authoritative guidance, 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. Under 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 generally 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. The price quotations reflect the average of the bid-ask mid-point from markets 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. The Registrant's derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using models that consider 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 and are categorized in Level 3.

The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of nonperformance and credit 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 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 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. 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 observable inputs and 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.

Table of Contents

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Note 11 — Fair Value of Financial Assets and Liabilities and Note 12 — 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. 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. 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.

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 assess negative evidence, such as the expiration of historical operating loss or tax credit carryforwards, that could indicate the Registrant's inability to realize its deferred tax assets. Based on the combined assessment, the Registrants record valuation allowances for deferred tax assets when it is more-likely-than-not such benefit will not be realized in future periods.

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. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

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 amount recorded may differ from the actual expense incurred when the uncertainty is resolved. Such difference could have a significant impact in the Registrants' 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. Annual studies and/or reviews are conducted at ComEd, PECO, BGE and DPL to determine future remediation requirements for MGP sites and estimates are adjusted accordingly. In addition, periodic reviews are performed at each of the Registrants to assess the adequacy of other environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant impact in the Registrants' consolidated financial statements. See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional 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 impact in the Registrants' consolidated financial statements.

Table of Contents

Revenue Recognition (All Registrants)

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

The accounting treatment for revenue recognition is based on the nature of the underlying transaction and applicable authoritative guidance. The Registrants primarily apply the Revenue from Contracts with Customers, Derivative and Alternative Revenue Program (ARP) guidance to recognize revenue as discussed in more detail below.

Revenue from Contracts with Customers. Under the Revenue from Contracts with Customers guidance, the Registrants recognize revenues in the period in which the performance obligations within contracts with customers are satisfied, which generally occurs when power, natural gas, and other energy-related commodities are physically delivered to the customer. Transactions of the Registrants within the scope of Revenue from Contracts with Customers generally include non-derivative agreements, contracts that are designated as normal purchases and normal sales (NPNS), sales to utility customers under regulated service tariffs, and spot-market energy commodity sales, including settlements with independent system operators.

The determination of Generation’s and the Utility Registrants' retail power and natural gas 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 revenues 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 also impact the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged. See Note 1 — Significant Accounting Policies of the Combined Notes to Consolidated Financial Statements for additional information.

Derivative Revenues. The Registrants record revenues and expenses using the mark-to-market method of accounting for transactions that are accounted for as derivatives. These derivative 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, unrealized gains and losses from changes in the fair value of open contracts, and realized gains and losses.

Alternative Revenue Program Accounting. Certain of the Utility Registrants’ ratemaking mechanisms qualify as Alternative Revenue Programs (ARPs) if they (i) are established by a regulatory order and allow for automatic adjustment to future rates, (ii) provide for additional revenues (above those amounts currently reflected in the price of utility service) that are objectively determinable and probable of recovery, and (iii) allow for the collection of those additional revenues within 24 months following the end of the period in which they were recognized. For mechanisms that meet these criteria, which include the Utility Registrants’ formula rate and revenue decoupling mechanisms, the Utility Registrants adjust revenue and record an offsetting regulatory asset or liability once the condition or event allowing additional billing or refund has occurred. The ARP revenues presented in the Utility Registrants’ Consolidated Statements of Operations and Comprehensive Income include both: (i) the recognition of “originating” ARP revenues (when the regulator-specified condition or event allowing for additional billing or refund has occurred) and (ii) an equal and offsetting reversal of the “originating” ARP revenues as those amounts are reflected in the price of utility service and recognized as Revenue from Contracts with Customers.

ComEd records ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in

Table of Contents

accordance with their formula rate mechanisms. Estimates of the current year revenue requirement are based on actual and/or forecasted costs 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 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Allowance for Uncollectible Accounts (Utility Registrants)

Utility Registrants 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. 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 a historical average of charge-offs as a percentage of accounts receivable in each risk segment. The Utility Registrants' customer 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.

Results of Operations by Registrant

The Registrants' Results of Operations includes discussion of RNF, which is a financial measure not 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 CODMs for Exelon and Generation evaluate the performance of Generation's electric business activities and allocate resources based on RNF. Generation believes that RNF is a useful measure because it provides information that can be used to evaluate its operational performance. For the Utility Registrants, their Operating revenues reflect the full and current recovery of commodity procurement costs given the rider mechanisms approved by their respective state regulators. The commodity procurement costs, which are recorded in Purchased power and fuel expense, and the associated revenues can be volatile. Therefore, the Utility Registrants believe that RNF is a useful measure because it excludes the effect on Operating revenues caused by the volatility in these expenses.

Table of Contents

Results of Operations—Generation

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$20,437	$18,500	$ 1,937	$17,757	$ 743
Purchased power and fuel expense	11,693	9,690	(2,003)	8,830	(860)
Revenues net of purchased power and fuel expense	8,744	8,810	(66)	8,927	(117)
Other operating expenses					
Operating and maintenance	5,464	6,299	835	5,663	(636)
Depreciation and amortization	1,797	1,457	(340)	1,879	422
Taxes other than income	556	555	(1)	506	(49)
Total other operating expenses	7,817	8,311	494	8,048	(263)
Gain (loss) on sales of assets and businesses	48	2	46	(59)	61
Bargain purchase gain	—	233	(233)	—	233
Gain on deconsolidation of business	—	213	(213)	—	213
Operating income	975	947	28	820	127
Other income and (deductions)					
Interest expense	(432)	(440)	8	(364)	(76)
Other, net	(178)	948	(1,126)	401	547
Total other income and (deductions)	(610)	508	(1,118)	37	471
Income before income taxes	365	1,455	(1,090)	857	598
Income taxes	(108)	(1,376)	(1,268)	282	1,658
Equity in losses of unconsolidated affiliates	(30)	(33)	3	(25)	(8)
Net income	443	2,798	(2,355)	550	2,248
Net income attributable to noncontrolling interests	73	88	(15)	67	21
Net income attributable to membership interest	$370	$2,710	$ (2,340)	$483	$ 2,227

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income attributable to membership interest decreased by $2,340 million primarily due to:

- Impacts associated with the one-time remeasurement of deferred income taxes in 2017 as a result of the TCJA;
- Net unrealized losses on NDT funds in 2018 compared to net gains in 2017;
- Lower realized energy prices;
- Accelerated depreciation and amortization due to the decision to early retire the Oyster Creek and TMI nuclear facilities;
- The gain associated with the FitzPatrick acquisition in 2017;
- Increased mark-to-market losses;
- The gain recorded upon deconsolidation of EGTP's net liabilities in 2017;

Table of Contents

- The absence of EGTP earnings resulting from its deconsolidation in the fourth quarter of 2017; and
- Long-lived asset impairments of certain merchant wind assets in West Texas.

The decreases were partially offset by;

- The impact of the New York and Illinois ZEC revenue (including the impact of zero emission credits generated in Illinois from June 1, 2017 through December 31, 2017);
- Long-lived asset impairments primarily related to the EGTP assets held for sale in 2017;
- Increased capacity prices;
- The impact of lower federal income tax rate as a result of the TCJA at Generation;
- Net realized gains on NDT funds; and
- Decreased nuclear outage days.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income attributable to membership interest increased by $2,227 million primarily due to:

- Impacts associated with the one-time remeasurement of deferred income taxes as a result of the TCJA;
- The gain associated with the FitzPatrick acquisition;
- Accelerated depreciation and amortization due to the decision to early retire the TMI nuclear facility in 2017 compared to the previous decision in 2016 to early retire the Clinton and Quad Cities nuclear facilities;
- Higher net unrealized and realized gains on NDT funds;
- The impact of the New York ZEC revenue;
- The gain recorded upon deconsolidation of EGTP's net liabilities;
- Increased capacity prices; and
- Decreased nuclear outage days.

These increases were partially offset by:

- Long-lived asset impairments primarily related to the EGTP assets held for sale;
- Lower realized energy prices;
- The conclusion of the Ginna Reliability Support Services Agreement;
- Increased costs related to the acquisition of the FitzPatrick nuclear facility; and
- Increased mark-to-market losses.

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 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. Generation's six reportable segments are Mid-Atlantic, Midwest, New England, ERCOT and Other Power Regions. During the first quarter of 2019, due to a change in economics in our New England region, Generation is changing the way that information is reviewed by the CODM. The New England region will no longer be regularly reviewed as a separate region by the CODM nor will it be presented separately in any external information presented to third parties. Information for the New England region will be reviewed by the CODM as part of Other Power Regions. As a result, beginning in the first quarter of 2019, Generation will disclose five reportable segments consisting of Mid-Atlantic, Midwest, New York, ERCOT and

Table of Contents

Other Power Regions. See Note 24 - Segment Information of the Combined Notes to Consolidated Financial Statements for additional information on these reportable segments.

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 overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in Other: amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions; accelerated nuclear fuel amortization associated with nuclear decommissioning; and other miscellaneous revenues.

Generation evaluates the operating performance of electric business activities using the measure of RNF. Operating revenues include all sales to third parties and affiliated sales to the Utility Registrants. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for owned generation and fuel costs associated with tolling agreements.

For the years ended December 31, 2018 compared to 2017 and December 31, 2017 compared to 2016, RNF by region were as follows:

			2018 vs. 2017			2017 vs. 2016	
	2018	2017	Variance	% Change	2016	Variance	% Change
Mid-Atlantic[(a)]	$3,073	$3,214	$(141)	(4.4)%	$3,317	$(103)	(3.1)%
Midwest[(a)]	3,135	2,820	315	11.2 %	2,971	(151)	(5.1)%
New England	354	514	(160)	(31.1)%	438	76	17.4 %
New York[(c)]	1,122	1,008	114	11.3 %	752	256	34.0 %
ERCOT	258	332	(74)	(22.3)%	281	51	18.1 %
Other Power Regions	375	305	70	23.0 %	336	(31)	(9.2)%
Total electric revenues net of purchased power and fuel expense	8,317	8,193	124	1.5 %	8,095	98	1.2 %
Proprietary Trading	42	18	24	n.m.	15	3	n.m.
Mark-to-market losses	(319)	(175)	(144)	82.3 %	(41)	(134)	326.8 %
Other[(b)]	704	774	(70)	(9.0)%	858	(84)	(9.8)%
Total revenue net of purchased power and fuel expense	$8,744	$8,810	$(66)	(0.7)%	$8,927	$(117)	(1.3)%

(a) Includes results of transactions with PECO and BGE in the Mid-Atlantic region and results of transactions with ComEd in the Midwest region. As a result of the PHI merger, includes results of transactions with Pepco, DPL and ACE in the Mid-Atlantic region beginning on March 24, 2016.

(b) Other represents activities not allocated to a region. Includes amortization of intangible assets related to commodity contracts recorded at fair value of a $54 million decrease to RNF and a $57 million decrease to RNF for the years ended December 31, 2017 and 2016, respectively, accelerated nuclear fuel amortization associated with announced early plant retirements, as discussed in Note 8 - Early Plant Retirements of the Combined Notes to Consolidated Financial Statements, of $57 million, $12 million and $60 million for the years ended December 31, 2018, 2017 and 2016, respectively, and gain on the settlement of a long-term gas supply agreement of $75 million for the year ended December 31, 2018.

(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Table of Contents

Generation’s supply sources by region are summarized below:

Supply Source (GWhs)	2018	2017	2018 vs. 2017 Variance	2018 vs. 2017 % Change	2016	2017 vs. 2016 Variance	2017 vs. 2016 % Change
Nuclear Generation[a]							
Mid-Atlantic	64,099	64,466	(367)	(0.6)%	63,447	1,019	1.6%
Midwest	94,283	93,344	939	1.0%	94,668	(1,324)	(1.4)%
New York[c]	26,640	25,033	1,607	6.4%	18,684	6,349	34.0%
Total Nuclear Generation	185,022	182,843	2,179	1.2%	176,799	6,044	3.4%
Fossil and Renewables							
Mid-Atlantic	3,670	2,789	881	31.6%	2,731	58	2.1%
Midwest	1,373	1,482	(109)	(7.4)%	1,488	(6)	(0.4)%
New England	4,731	7,179	(2,448)	(34.1)%	6,968	211	3.0%
New York	3	3	—	—%	3	—	—%
ERCOT	11,180	12,072	(892)	(7.4)%	6,785	5,287	77.9%
Other Power Regions	8,525	6,869	1,656	24.1%	8,179	(1,310)	(16.0)%
Total Fossil and Renewables	29,482	30,394	(912)	(3.0)%	26,154	4,240	16.2%
Purchased Power							
Mid-Atlantic	6,506	9,801	(3,295)	(33.6)%	16,874	(7,073)	(41.9)%
Midwest	996	1,373	(377)	(27.5)%	2,255	(882)	(39.1)%
New England	26,033	18,517	7,516	40.6%	16,632	1,885	11.3%
New York	—	28	(28)	—%	—	28	—%
ERCOT	6,550	7,346	(796)	(10.8)%	10,637	(3,291)	(30.9)%
Other Power Regions	18,965	14,530	4,435	30.5%	13,589	941	6.9%
Total Purchased Power	59,050	51,595	7,455	14.4%	59,987	(8,392)	(14.0)%
Total Supply/Sales by Region							
Mid-Atlantic[b]	74,275	77,056	(2,781)	(3.6)%	83,052	(5,996)	(7.2)%
Midwest[b]	96,652	96,199	453	0.5%	98,411	(2,212)	(2.2)%
New England	30,764	25,696	5,068	19.7%	23,600	2,096	8.9%
New York	26,643	25,064	1,579	6.3%	18,687	6,377	34.1%
ERCOT	17,730	19,418	(1,688)	(8.7)%	17,422	1,996	11.5%
Other Power Regions	27,490	21,399	6,091	28.5%	21,768	(369)	(1.7)%
Total Supply/Sales by Region	273,554	264,832	8,722	3.3%	262,940	1,892	0.7%

(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) 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 beginning on March 24, 2016.
(c) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

Table of Contents

For the years ended December 31, 2018 compared to 2017 and December 31, 2017 compared to 2016, changes in RNF by region were as follows:

	2018 vs. 2017 Increase (Decrease)	Description	2017 vs. 2016 Increase (Decrease)	Description
Mid-Atlantic	$(141)	• lower realized energy prices, partially offset by • increased capacity prices	$(103)	• lower load volumes • lower realized energy prices • decreased capacity prices, partially offset by • the absence of oil inventory write-downs in 2017 • decreased nuclear outage days
Midwest	315	• the impact of the Illinois ZES • increased capacity prices, partially offset by • lower realized energy prices	(151)	• lower realized energy prices • increased nuclear outage days, partially offset by • decreased fuel prices
New England	(160)	• lower realized energy prices, partially offset by • increased capacity prices	76	• increased capacity prices, partially offset by • lower realized energy prices
New York	114	• impact of the New York CES • acquisition of Fitzpatrick, partially offset by • the conclusion of the Ginna Reliability Support Service Agreement	256	• the impact of the New York CES • acquisition of FitzPatrick, partially offset by • conclusion of the Ginna Reliability Support Service Agreement • lower realized energy prices
ERCOT	(74)	• deconsolidation of EGTP in 2017, partially offset by • the addition of two combined-cycle gas turbines in Texas	51	• the addition of two combined-cycle gas turbines in Texas, partially offset by • lower realized energy prices
Other Power Regions	70	• higher realized energy prices	(31)	• lower realized energy prices
Proprietary Trading	24	• congestion activity	3	• congestion activity
Mark-to-Market	(144)	• losses on economic hedging activities of $319 million in 2018 compared to losses of $175 million in 2017	(134)	• losses on economic hedging activities of $175 million in 2017 compared to losses of $41 million in 2016
Other	(70)	• decline in revenues related to the energy efficiency business • the sale of Generation's electrical contracting business in 2018 • accelerated nuclear fuel amortization associated with announced early plant retirements, partially offset by • the absence of amortization of energy contracts recorded at fair value associated with prior acquisitions • gain on the settlement of a long-term gas supply agreement	(84)	• the impacts of declining natural gas prices on Generation's natural gas portfolio • decline in revenues related to the distributed generation business, partially offset by • decrease in accelerated nuclear fuel amortization associated with announced early plant retirements
Total	$(66)		$(117)	

107

Table of Contents

Nuclear Fleet Capacity Factor. The following table presents nuclear fleet operating data for the Generation-operated plants, which reflects ownership percentage of stations operated by Exelon, excluding Salem, which is operated by PSEG Nuclear, LLC and including the ownership of the FitzPatrick nuclear facility from March 31, 2017. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Generation considers capacity factor to be a useful measure to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2018	2017	2016
Nuclear fleet capacity factor	94.6%	94.1%	94.6%
Refueling outage days	274	293	245
Non-refueling outage days	38	53	63

The changes in Operating and maintenance expense, consisted of the following:

	Increase (Decrease) 2018 vs. 2017[a]
Impairment and related charges of certain generating assets[b]	$ (432)
Merger and integration costs[c]	(68)
Insurance	(36)
Pension and non-pension postretirement benefits expense	(22)
BSC costs	13
Plant retirements and divestitures[d]	53
Accretion expense	(14)
Nuclear refueling outage costs, including the co-owned Salem plant	(24)
Labor, other benefits, contracting and materials[e]	(255)
Vacation policy change[f]	40
Change in environmental liabilities	(45)
Other	(45)
Decrease in operating and maintenance expense	$ (835)

(a) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

(b) Primarily reflects the impairment of certain wind projects in 2018 and charges to earnings related to impairments as a result of the EGTP assets in 2017.

(c) Primarily reflects merger and integration costs associated with the PHI and FitzPatrick acquisitions, including, if and when applicable, professional fees, employee-related expenses and integration activities.

(d) Primarily represents the announcement to early retire the Oyster Creek nuclear facility, a charge associated with a remeasurement of the Oyster Creek ARO compared to the previous decision to early retire the TMI nuclear facility in 2017.

(e) Primarily reflects decreased spending related to energy efficiency projects and decreased costs related to the sale of Generation's electrical contracting business.

(f) Primarily reflects the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.

Table of Contents

	Increase (Decrease) 2017 vs. 2016[(a)]
Impairment and related charges of certain generating assets [(b)]	$ 307
Merger and integration costs	13
ARO update[(c)]	84
Pension and non-pension postretirement benefits expense[(c)]	10
BSC costs	23
Plant retirements and divestitures[(d)]	127
Accretion expense[(e)]	35
Nuclear refueling outage costs, including the co-owned Salem plant[(f)]	104
Merger commitments[(g)]	(53)
Labor, other benefits, contracting and materials[(h)]	38
Cost management program	(2)
Curtailment of Generation growth and development activities[(i)]	(24)
Vacation policy change[(j)]	(40)
Allowance for uncollectible accounts	33
Change in environmental liabilities	44
Other	(63)
Increase in operating and maintenance expense	$ 636

(a) Includes the ownership of the FitzPatrick nuclear facility from March 31, 2017.

(b) Primarily reflects charges to earnings related to impairments as a result of the EGTP assets in 2017 and impairment of Upstream assets and certain wind projects in 2016.

(c) Primarily reflects the non-cash benefit pursuant to the annual update of the nuclear decommissioning obligation related to the non-regulatory units in 2017 compared to 2016.

(d) Primarily represents the announcement of the early retirement of the TMI nuclear facility in 2017 compared to the previous decision to early retire the Clinton and Quad Cities nuclear facilities in 2016.

(e) Reflects the impact of increased accretion expenses primarily due to the acquisition of FitzPatrick on March 31, 2017.

(f) Primarily reflects an increase in the number of nuclear outage days during 2017 compared to 2016.

(g) Primarily represents costs incurred as part of the settlement orders approving the PHI merger during 2016.

(h) Reflects increased salaries, wages and contracting costs primarily related to the acquisition of the FitzPatrick nuclear facility beginning on March 31, 2017.

(i) Reflects the one-time recognition for a loss on sale of assets and 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.

(j) Represents the reversal of previously accrued vacation expenses as a result of a change in Exelon's vacation vesting policy.

Depreciation and amortization expense for the year ended December 31, 2018 compared to the year ended December 31, 2017 increased primarily due to accelerated depreciation and amortization expenses associated with the decision to early retire the Oyster Creek nuclear facility in 2018 compared to the previous decision to early retire the TMI nuclear facility in 2017.

Depreciation and amortization expense for the year ended December 31, 2017 compared to the year ended December 31, 2016 decreased 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 compared to the decision to early retire the TMI nuclear facility in 2017.

Gain (loss) on sales of assets and businesses for the year ended December 31, 2018 compared to the year ended December 31, 2017 increased due to Generation's 2018 sale of its electrical contracting business.

Gain (loss) on sales of assets and businesses for the year ended December 31, 2017 compared to the year ended December 31, 2016 increased 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.

Table of Contents

Bargain purchase gain for the year ended December 31, 2018 compared to the year ended December 31, 2017. decreased as a result of the gain associated with the FitzPatrick acquisition. See Note 5 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Gain on deconsolidation of business for the year ended December 31, 2018 compared to the year ended December 31, 2017 decreased due to the deconsolidation of EGTP's net liabilities, which included the previously impaired assets and related debt, as a result of the November 2017 bankruptcy filing. See Note 5 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

Other, Net decreased primarily due to the net decrease in unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units as described in the table below. Other, net also reflects $45 million, $209 million and $80 million for the years ended December 31, 2018, 2017 and 2016 respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. See Note 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding NDT funds.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units:

	2018	2017	2016
Net unrealized (losses) gains on NDT funds	$(483)	$521	$194
Net realized gains on sale of NDT funds	180	95	35

Effective income tax rates were (29.5)%, (94.6)% and 32.9% for the years ended December 31, 2018, 2017 and 2016, respectively. The increase is primarily related to impacts associated with the one-time remeasurement of deferred income taxes in 2017 as a result of the TCJA. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information of the change in the effective income tax rate.

Table of Contents

Results of Operations—ComEd

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$5,882	$5,536	$ 346	$5,254	$ 282
Purchased power expense	2,155	1,641	(514)	1,458	(183)
Revenues net of purchased power expense	3,727	3,895	(168)	3,796	99
Other operating expenses					
Operating and maintenance	1,335	1,427	92	1,530	103
Depreciation and amortization	940	850	(90)	775	(75)
Taxes other than income	311	296	(15)	293	(3)
Total other operating expenses	2,586	2,573	(13)	2,598	25
Gain on sales of assets	5	1	4	7	(6)
Operating income	1,146	1,323	(177)	1,205	118
Other income and (deductions)					
Interest expense, net	(347)	(361)	14	(461)	100
Other, net	33	22	11	(65)	87
Total other income and (deductions)	(314)	(339)	25	(526)	187
Income before income taxes	832	984	(152)	679	305
Income taxes	168	417	249	301	(116)
Net income	$664	$567	$ 97	$378	$ 189

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income increased by $97 million primarily due to higher electric distribution and energy efficiency formula rate earnings (reflecting the impacts of increased capital investment). The TCJA did not significantly impact Net income as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income increased $189 million primarily due to the recognition of the penalty and the after-tax interest due on the asserted penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in 2016 and increased electric distribution and transmission formula rate earnings (reflecting the impacts of increased capital investment and higher allowed electric distribution ROE). The higher Net income was partially offset by the impact of weather conditions in 2016. See Revenue Decoupling discussion below for additional information on the impact of weather.

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, REC and ZEC procurement costs and participation in customer choice programs. ComEd recovers electricity, REC and ZEC procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact the volume of deliveries, but do impact Operating revenues related to supplied electricity.

Table of Contents

The changes in RNF consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Weather[(a)]	$ —	$ (36)
Volume[(a)]	—	(5)
Pricing and customer mix[(a)]	—	(18)
Electric distribution revenue	(127)	170
Transmission revenue	(43)	60
Energy efficiency revenue[(b)]	47	16
Regulatory required programs[(b)]	(97)	(85)
Uncollectible accounts recovery, net	6	(7)
Other	46	4
Total (decrease) increase	$ (168)	$ 99

____

(a) For the year ended December 31, 2017, compared to the same period in 2016, the changes reflect the 2016 impacts of weather, volume and pricing and customer mix. Pursuant to the revenue decoupling provision in FEJA, ComEd began recording an adjustment to revenue in the first quarter of 2017 to eliminate the favorable or unfavorable impacts associated with variations in delivery volumes associated with above or below normal weather, number of customers or usage per customer.

(b) Beginning June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, beginning January 1, 2017, Operating revenues are not impacted by abnormal weather, usage per customer or number of customers as a result of a change to the electric distribution formula rate pursuant to FEJA.

Distribution Revenue. EIMA and FEJA provide 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. Electric distribution revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered and allowed ROE. During the year ended December 31, 2018, as compared to the same period in 2017, electric distribution revenue decreased $127 million, primarily due to the impact of the lower federal income tax rate, partially offset by increased revenues due to higher rate base and increased Depreciation expense. During the year ended December 31, 2017, as compared to the same period in 2016, electric distribution revenue increased $170 million, primarily due to increased capital investment, increased Depreciation expense, higher allowed ROE due to an increase in treasury rates and revenue decoupling impacts (as described above). See Operating and Maintenance Expense below and Note 4 — 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, capital 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. Transmission revenue decreased for the year ended December 31, 2018, primarily due to decreased peak load and the impact of the lower federal tax rate, partially offset by increased revenues due to higher rate base and increased Depreciation expense. Transmission revenue increased for the year ended December 31, 2017, primarily due to increased capital investment, higher Depreciation expense, and increased highest daily peak load. See Operating and Maintenance Expense below and Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Revenue. Beginning June 1, 2017, FEJA 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 FEJA, energy efficiency revenue varies from year to year based upon fluctuations in the underlying costs, investments being recovered, and allowed ROE. See Depreciation and amortization expense discussions below and Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Regulatory Required Programs represent revenues collected under approved rate riders to recover costs incurred for regulatory programs such as purchased power administrative costs and energy efficiency and demand response through June 1, 2017 pursuant to FEJA. The riders are designed to provide full and current cost recovery. The costs of such programs are included in Operating and maintenance expense. Revenues from regulatory programs decreased for the year ended December 31, 2018, as compared to the same period in 2017, and for the year ended December 31, 2017, as compared to the same period in 2016, primarily due to the fact that beginning on June 1, 2017, ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency formula rate over the weighted average useful life of the related energy efficiency measures.

Uncollectible Accounts Recovery, Net represents recoveries under the uncollectible accounts tariff. See Operating and maintenance expense discussion below for additional information on this tariff.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and recoveries of environmental costs associated with MGP sites. The increase in Other revenue for the years ended December 31, 2018, as compared to the same period in 2017 primarily reflects mutual assistance revenues associated with hurricane and winter storm restoration efforts. An equal and offsetting amount has been included in Operating and maintenance expense and Taxes other than income.

See Note 24 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ComEd's revenue disaggregation.

The changes in Operating and maintenance expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Baseline		
Labor, other benefits, contracting and materials[a]	$ 20	$ (41)
Pension and non-pension postretirement benefits expense	—	3
Storm costs	(19)	2
Uncollectible accounts expense—provision[b]	5	(6)
Uncollectible accounts expense—recovery, net[b]	1	(1)
BSC costs[a][c]	(5)	44
Other[a]	3	(19)
	5	(18)
Regulatory required programs		
Energy efficiency and demand response programs[d]	(97)	(85)
Decrease in operating and maintenance expense	$ (92)	$ (103)

(a) Includes costs associated with mutual assistance provided to other utilities in 2018. An equal and offsetting increase has been recognized in Operating revenues for the period presented.

(b) ComEd is allowed to recover from or refund to customers the difference between its annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. An equal and offsetting amount has been recognized in Operating revenues for the periods presented.

(c) For the year ended December 31, 2017, primarily reflects increased information technology support services from BSC and includes the $8 million write-off of a regulatory asset related to Constellation merger and integration costs for which recovery is no longer expected.

(d) Beginning June 1, 2017 ComEd is deferring energy efficiency costs as a regulatory asset that will be recovered through the energy efficiency over the weighted average useful life of the related energy efficiency measures.

Table of Contents

The increases in Depreciation and amortization expense consisted of the following:

	Increase 2018 vs. 2017	Increase 2017 vs. 2016
Depreciation expense[(a)]	$ 36	$ 60
Regulatory asset amortization[(b)]	53	7
Other	1	8
Total increase	$ 90	$ 75

____

(a) Primarily reflects ongoing capital expenditures.
(b) Beginning in June 2017, includes amortization of ComEd's energy efficiency formula rate regulatory asset.

The decrease in Interest expense, net, for the year ended 2018 compared to the same period in 2017, and for the year ended 2017 compared to the same period in 2016, consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Interest expense related to uncertain tax positions[(a)]	$ (13)	$ (104)
Interest expense on debt (including financing trusts)	2	6
Other	(3)	(2)
Decrease in interest expense, net	$ (14)	$ (100)

____

(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 2016 and 2017. See Note 14—Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

The increase in Other, net, for the year ended 2018 compared to the same period in 2017, and for the year ended 2017 compared to the same period in 2016, consisted of the following:

	Increase 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Other income and deductions, net[(a)]	$ 1	$ 88
AFUDC equity	7	(2)
Other	3	1
Increase (decrease) in Other, net	$ 11	$ 87

____

(a) Primarily reflects the recognition of the penalty related to the Tax Court's decision on Exelon's like-kind exchange tax position in 2016.

Effective income tax rates for the years ended December 31, 2018, 2017 and 2016, were 20.2%, 42.4% and 44.3%, respectively. The decrease in the effective income tax rate for the year ended December 31, 2018, compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. The decrease in the effective income tax rate for the year ended December 31, 2017, compared to the same period in 2016 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 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

Results of Operations—PECO

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$3,038	$2,870	$ 168	$2,994	$ (124)
Purchased power and fuel expense	1,090	969	(121)	1,047	78
Revenues net of purchased power and fuel expense	1,948	1,901	47	1,947	(46)
Other operating expenses					
Operating and maintenance	898	806	(92)	811	5
Depreciation and amortization	301	286	(15)	270	(16)
Taxes other than income	163	154	(9)	164	10
Total other operating expenses	1,362	1,246	(116)	1,245	(1)
Gain on sales of assets	1	—	1	—	—
Operating income	587	655	(68)	702	(47)
Other income and (deductions)					
Interest expense, net	(129)	(126)	(3)	(123)	(3)
Other, net	8	9	(1)	8	1
Total other income and (deductions)	(121)	(117)	(4)	(115)	(2)
Income before income taxes	466	538	(72)	587	(49)
Income taxes	6	104	98	149	45
Net income	$460	$434	$ 26	$438	$ (4)

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income was higher due to favorable weather and volumes. The TCJA did not significantly impact Net Income as the favorable income tax impacts were predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income was lower primarily due to unfavorable weather. The TCJA did not significantly impact Net Income as the favorable income tax impacts were predominantly offset by lower revenues resulting from the requirement to pass back the tax savings through customer rates.

Revenues Net of Purchased Power and Fuel Expense. There are certain drivers of Operating revenues that are fully offset by their impact on Purchased power and fuel expenses such as commodity and REC procurement costs and participation in customer choice programs. PECO's recovers electricity, natural gas and REC procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity and natural gas from competitive electric generation and natural gas suppliers. Customer choice programs do not impact the volume of deliveries or RNF, but impact Operating revenues related to supplied electricity and natural gas.

Table of Contents

The changes in RNF consisted of the following:

	2018 vs. 2017 Increase (Decrease)			2017 vs. 2016 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$39	$22	$61	$(28)	$ 4	$(24)
Volume	37	4	41	(18)	3	(15)
Pricing	(75)	(1)	(76)	8	2	10
Regulatory required programs	11	—	11	(31)	—	(31)
Other	14	(4)	10	14	—	14
Total increase (decrease)	$26	$21	$47	$(55)	$ 9	$(46)

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. For the year ended December 31, 2018 compared to the same period in 2017 RNF was increased by the impact of favorable weather conditions in PECO's service territory. For the year ended December 31, 2017 compared to the same period in 2016 RNF was reduced by the impact of unfavorable weather conditions in PECO’s service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO’s service territory. The changes in heating and cooling degree days in PECO’s service territory for the years ended December 31, 2018 and December 31, 2017 compared to the same periods in 2017 and 2016, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	4,539	3,949	4,487	14.9 %	1.2 %
Cooling Degree-Days	1,584	1,490	1,411	6.3 %	12.3 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	3,949	4,041	4,603	(2.3)%	(14.2)%
Cooling Degree-Days	1,490	1,726	1,290	(13.7)%	15.5 %

Volume. Delivery volume, exclusive of the effects of weather, for the year ended December 31, 2018 compared to the same period in 2017, was driven by electric and primarily reflects the impact of moderate economic and customer growth partially offset by the impact of energy efficiency initiatives on customer usages primarily in the residential class. Additionally, the increase represents a shift in the volume profile across classes from the commercial and industrial classes to the residential class.

Delivery volume, exclusive of the effects of weather, for the year ended December 31, 2017 compared to the same period in 2016, was driven by electric and primarily reflects the impact of energy efficiency initiatives on customer usages for residential and small commercial and industrial electric classes, partially offset by solid customer growth. Additionally, the decrease represents a shift in the volume profile across classes from residential and small commercial and industrial to large commercial and industrial.

Table of Contents

Electric Retail Deliveries to Customers (in GWhs)	2018	2017	% Change 2018 vs. 2017	Weather - Normal % Change	2016	% Change 2017 vs. 2016	Weather - Normal % Change
Retail Deliveries [(a)]							
Residential	14,005	13,024	7.5 %	3.5 %	13,664	(4.7)%	(1.8)%
Small commercial & industrial	8,177	7,968	2.6 %	0.2 %	8,099	(1.6)%	(1.1)%
Large commercial & industrial	15,516	15,426	0.6 %	0.4 %	15,263	1.1 %	1.4 %
Public authorities & electric railroads	761	809	(5.9)%	(5.6)%	890	(9.1)%	(9.1)%
Total electric retail deliveries	38,459	37,227	3.3 %	1.4 %	37,916	(1.8)%	(0.5)%

(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.

	As of December 31,		
Number of Electric Customers	2018	2017	2016
Residential	1,480,925	1,469,916	1,456,585
Small commercial & industrial	152,797	151,552	150,142
Large commercial & industrial	3,118	3,112	3,096
Public authorities & electric railroads	9,565	9,569	9,823
Total	1,646,405	1,634,149	1,619,646

Natural Gas Deliveries to customers (in mmcf)	2018	2017	% Change 2018 vs. 2017	Weather-Normal % Change	2016	% Change 2017 vs. 2016	Weather-Normal % Change
Retail Deliveries [(a)]							
Residential	43,450	37,919	14.6 %	1.8 %	36,872	2.8 %	0.6 %
Small commercial & industrial	21,997	20,515	7.2 %	(0.4)%	19,525	5.1 %	1.9 %
Large commercial & industrial	65	23	182.6 %	175.8 %	50	(54.0)%	28.3 %
Transportation	26,595	26,382	0.8 %	(3.2)%	27,630	(4.5)%	(2.3)%
Total natural gas deliveries	92,107	84,839	8.6 %	(0.2)%	84,077	0.9 %	0.1 %

(a) Reflects delivery volumes and revenue from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges.

	As of December 31,		
Number of Gas Customers	2018	2017	2016
Residential	482,255	477,213	472,606
Small commercial & industrial	44,170	43,887	43,664
Large commercial & industrial	1	5	4
Transportation	754	771	790
Total	527,180	521,876	517,064

Pricing for the year ended December 31, 2018 compared to the same period in 2017 reflects the anticipated pass back of the Tax Cuts and Jobs Act tax savings through customer rates.

Table of Contents

The increase in Operating revenues net of purchased power and fuel expense as a result of pricing for the year ended December 31, 2017 compared to the same period in 2016 reflects higher overall effective rates due to decreased usage in the residential and small commercial and industrial customer classes. Operating revenues net of fuel expense as a result of pricing remained relatively consistent. See Note 4 — Regulatory Matters for additional information.
Regulatory Required Programs represent 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.
Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and wholesale transmission revenue.
See Note 24—Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of PECO's revenue disaggregation.
The changes in Operating and maintenance expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Baseline		
Labor, other benefits, contracting and materials	$ 10	$ 17
Storm-related costs [(a)]	63	(7)
Pension and non-pension postretirement benefits expense	(7)	(3)
BSC costs	—	4
Uncollectible accounts expense	7	(5)
Other	9	—
	82	6
Regulatory required programs		
Energy efficiency	10	(10)
Other	—	(1)
	10	(11)
Increase (decrease) in operating and maintenance expense	$ 92	$ (5)

____
(a) Reflects increased costs incurred from the Q1 2018 winter storms.
The changes in Depreciation and amortization expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Depreciation expense [(a)]	$ 13	$ 17
Regulatory asset amortization	2	(1)
Increase in depreciation and amortization expense	$ 15	$ 16

____
(a) Depreciation expense increased due to ongoing capital expenditures.
Taxes other than income increased for the year ended December 31, 2018, compared to the same period in 2017, primarily due to an increase in gross receipts tax driven by increased electric revenue.
Taxes other than income decreased for the year ended December 31, 2017, compared to the same period in 2016, primarily due to a decrease in gross receipts tax driven by decreases in electric revenue.

Table of Contents

Effective income tax rates were 1.3%, 19.3% and 25.4% for the years ended December 31, 2018, 2017 and 2016, respectively. The decrease is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information of the change in effective income tax rates.

Results of Operations—BGE

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$3,169	$3,176	$ (7)	$3,233	$ (57)
Purchased power and fuel expense	1,182	1,133	(49)	1,294	161
Revenues net of purchased power and fuel expense	1,987	2,043	(56)	1,939	104
Other operating expenses					
Operating and maintenance	777	716	(61)	737	21
Depreciation and amortization	483	473	(10)	423	(50)
Taxes other than income	254	240	(14)	229	(11)
Total other operating expenses	1,514	1,429	(85)	1,389	(40)
Gain on sales of assets	1	—	1	—	—
Operating income	474	614	(140)	550	64
Other income and (deductions)					
Interest expense, net	(106)	(105)	(1)	(103)	(2)
Other, net	19	16	3	21	(5)
Total other income and (deductions)	(87)	(89)	2	(82)	(7)
Income before income taxes	387	525	(138)	468	57
Income taxes	74	218	144	174	(44)
Net income	313	307	6	294	13
Preference stock dividends	—	—	—	8	8
Net income attributable to common shareholder	$313	$307	$ 6	$286	$ 21

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income attributable to common shareholder increased by $6 million primarily due to an increase in transmission formula rate revenues and the absence of the 2017 impairment of certain transmission-related income tax regulatory assets offset by increased storm restoration costs as a result of storms in March 2018 and September 2018. The TCJA did not significantly impact Net income attributable to common shareholder as the favorable income tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income attributable to common shareholder increased by $21 million primarily due to the impacts of the electric and natural gas distribution rate orders issued by the MDPSC in June 2016 and July 2016, an increase in transmission formula rate revenues, the absence of cost disallowances resulting from the 2016 distribution rate orders issued by the MDPSC, and decreased storm costs in 2017. These increases were partially offset by the favorable 2016 settlement of the Baltimore City conduit fee dispute, the initiation of cost recovery of the AMI programs under the distribution rate orders and increased capital investment, higher income tax expense primarily resulting from higher taxable income as well as a 2016 favorable adjustment, and the 2017 impairment of certain transmission-related income tax regulatory assets.

Table of Contents

Revenues Net of Purchased Power and Fuel Expense. There are certain drivers to Operating revenues that are fully offset by their impact on Purchased power and fuel expense, such as commodity procurement costs and participation in customer choice programs. BGE recovers electricity, natural gas and other procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity and natural gas from electric generation and natural gas competitive suppliers. Customer choice programs do not impact the volume of deliveries or RNF but impact Operating revenues related to supplied electricity and natural gas.

The changes in RNF consisted of the following:

	2018 vs. 2017			2017 vs. 2016		
	Increase (Decrease)			Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase (decrease)	$(62)	$(28)	$(90)	$21	$29	$50
Regulatory required programs	2	2	4	17	3	20
Transmission revenue	15	—	15	18	—	18
Other, net	5	10	15	5	11	16
Total (decrease) increase	$(40)	$(16)	$(56)	$61	$43	$104

Revenue Decoupling. The demand for electricity and natural gas is affected by weather and customer usage. However, Operating revenues are not impacted by abnormal weather or usage per customer as a result of a bill stabilization adjustment (BSA) that provides for a fixed distribution charge per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

	As of December 31,		
Number of Electric Customers	2018	2017	2016
Residential	1,168,372	1,160,783	1,150,096
Small commercial & industrial	113,915	113,594	113,230
Large commercial & industrial	12,253	12,155	12,053
Public authorities & electric railroads	262	272	280
Total	1,294,802	1,286,804	1,275,659

	As of December 31,		
Number of Gas Customers	2018	2017	2016
Residential	633,757	629,690	623,647
Small commercial & industrial	38,332	38,392	37,941
Large commercial & industrial	5,954	5,855	6,314
Total	678,043	673,937	667,902

Distribution Revenues decreased during the year ended December 31, 2018, compared to the same period in 2017, primarily due to the impact of reduced distribution rates to reflect the lower federal income tax rate and increased during the year ended December 31, 2017, compared to the same period in 2016, primarily due to the impact of the electric and natural gas distribution rate changes that became effective in June 2016 in accordance with the electric and natural gas distribution rate case orders in June 2016 and July 2016. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as conservation, demand response, STRIDE, and the POLR mechanism. The riders are

Table of Contents

designed to provide full and current cost 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.

Transmission Revenue. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital 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. Transmission revenue increased during the years ended December 31, 2018 and 2017 primarily due to increases in capital investment and operating and maintenance expense recoveries. See Operating and maintenance expense below and Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Other revenue includes revenue related to late payment charges, mutual assistance revenues, off-system sales and service application fees.

See Note 24 — Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of BGE's revenue disaggregation.

The changes in Operating and maintenance expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Baseline		
Impairment on long-lived assets and losses on regulatory assets[(a)]	$ —	$ (50)
Labor, other benefits, contracting and materials	18	(11)
Pension and non-pension postretirement benefits expense	(2)	—
Storm-related costs[(b)]	39	(13)
Uncollectible accounts expense	2	7
BSC costs	7	16
Conduit lease settlement[(c)]	—	15
Other	3	7
	$ 67	$ (29)
Regulatory Required Programs		
Other	(6)	8
Total (decrease) increase	$ 61	$ (21)

(a) See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on Smart Meter and Smart Grid Investments.

(b) Reflects increased storm restoration costs incurred from storms in Q1 2018 and Q3 2018.

(c) See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

The changes in Depreciation and amortization expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Depreciation expense[(a)]	$ 25	$ 13
Regulatory asset amortization[(b)]	(24)	25
Regulatory required programs	9	12
Increase in depreciation and amortization expense	$ 10	$ 50

____

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory asset amortization decreased for the year ended December 31, 2018 compared to the same period in 2017, primarily due to certain regulatory assets that became fully amortized as of December 31, 2017 and increased for the year ended December 31, 2017 compared to the same period in 2016, primarily due 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 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Taxes other than income increased for the year ended December 31, 2018 compared to the same period in 2017, and for the year ended December 31, 2017 compared to the same period in 2016, primarily due to an increase in property taxes.

Effective income tax rates were 19.1%, 41.5% and 37.2% for the years ended December 31, 2018, 2017 and 2016, respectively. Income taxes decreased for the year ended December 31, 2018 compared to the same period in 2017, primarily due to the lower federal income tax rate as a result of the TCJA. See Note 14 — 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—PHI

PHI’s results of operations include the results of its three reportable segments, Pepco, DPL and ACE. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services and the costs are directly charged or allocated to the applicable subsidiaries. Additionally, the results of PHI's corporate operations include interest costs from various financing activities. For "Predecessor" reporting periods, PHI's results of operations also include the results of PES and PCI. See Note 24 — 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.

The following tables sets forth PHI's GAAP Net Income (Loss) by Registrant. As a result of the PHI Merger, the tables 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. The "Successor" reporting periods represents PHI's results of operations for the years ended December 31, 2018 and 2017 as well as March 24, 2016 to December 31, 2016. See the results of operations for Pepco, DPL, and ACE for additional information by segment.

	Successor				Predecessor
	For the Years Ended December 31,		Favorable (unfavorable) 2018 vs. 2017 variance	March 24 to December 31,	January 1 to March 23,
	2018	2017		2016	2016
PHI	$398	$362	$ 36	$ (61)	$ 19

Table of Contents

	For the Years Ended December 31,		Favorable (unfavorable) 2018 vs. 2017 variance	For the Years Ended December 31,		Favorable (unfavorable) 2017 vs. 2016 variance
	2018	2017		2017	2016	
Pepco	$210	$205	$ 5	$205	$42	$ 163
DPL	120	121	(1)	121	(9)	130
ACE	75	77	(2)	77	(42)	119
Other[a]	(7)	(41)	34	(41)	n/a	n/a

(a) Primarily includes eliminating and consolidating adjustments, PHI’s corporate operations, shared service entities and other financing activities. Not included for 2016 due to PHI Predecessor periods not being comparable.

Successor Year Ended December 31, 2018 Compared to Successor Year Ended December 31, 2017. Net income increased by $36 million primarily due to distribution rate increases (not reflecting the impact of the TCJA), favorable weather and volume, the absence of 2017 impairments of certain transmission-related income tax regulatory assets and the DC sponsorship intangible asset, partially offset by an increase in asset retirement obligations primarily related to asbestos identified at the Buzzard Point property and the deferral of accumulated merger integration cost as regulatory assets in 2017. The TCJA did not significantly impact Net income as the favorable tax impacts were predominantly offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Successor Period of March 24, 2016 to December 31, 2016. Net loss 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.

Predecessor Period of January 1, 2016 to March 23, 2016. Net income 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.

Table of Contents

Results of Operations—Pepco

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$2,239	$2,158	$ 81	$2,186	$ (28)
Purchased power expense	654	614	(40)	706	92
Revenues net of purchased power expense	1,585	1,544	41	1,480	64
Other operating expenses					
Operating and maintenance	501	454	(47)	642	188
Depreciation and amortization	385	321	(64)	295	(26)
Taxes other than income	379	371	(8)	377	6
Total other operating expenses	1,265	1,146	(119)	1,314	168
Gain on sales of assets	—	1	(1)	8	(7)
Operating income	320	399	(79)	174	225
Other income and (deductions)					
Interest expense, net	(128)	(121)	(7)	(127)	6
Other, net	31	32	(1)	36	(4)
Total other income and (deductions)	(97)	(89)	(8)	(91)	2
Income before income taxes	223	310	(87)	83	227
Income taxes	13	105	92	41	(64)
Net income	$210	$205	$ 5	$42	$ 163

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income increased by $5 million primarily due to higher electric distribution base rates (not reflecting the impact of the TCJA) in Maryland that became effective October 2017 and June 2018 and higher electric distribution base rates (not reflecting the impact of the TCJA) in the District of Columbia that became effective August 2017 and August 2018, partially offset by an increase in asset retirement obligations related primarily to the Buzzard Point property, deferral of accumulated merger integration costs as regulatory assets in 2017 and higher regulatory asset amortization due to additional regulatory assets related to rate case activity. The TCJA did not significantly impact Net income as the favorable tax impacts were predominantly offset by lower revenues resulting from pass back of tax savings through customer rates.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income increased by $163 million primarily due to a decrease in Operating and maintenance expense due to merger-related costs recognized in March 2016, higher electric distribution base rates in Maryland that became effective November 2016 and October 2017 and higher electric distribution base rates in the District of Columbia that became effective August 2017, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective November 2016. Income taxes expense included unrecognized tax benefits of $21 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the $14 million December 2017 impairment of certain transmission related income tax regulatory assets.

Table of Contents

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 and REC procurement costs and participation in customer choice programs. Pepco recovers electricity and REC procurement costs from customers with a slight mark-up. Therefore, fluctuations in these costs have minimal impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries or RNF, but impact Operating revenues related to supplied electricity.

The changes in RNF consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Volume	$ 12	$ 16
Distribution revenue	(3)	66
Regulatory required programs	35	(12)
Transmission revenues	—	9
Other	(3)	(15)
Total increase	$ 41	$ 64

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution in both Maryland and the District of Columbia are not impacted by abnormal weather or usage per customer as a result of a bill stabilization adjustment (BSA) that provides for a fixed distribution charge per customer by customer class. While Operating revenues are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

Volume, exclusive of the effects of weather, increased for the year ended December 31, 2018 compared to the same period in 2017, and for the year ended 2017 compared to the same period in 2016 primarily due to the impact of residential customer growth.

	As of December 31,		
Number of Electric Customers	2018	2017	2016
Residential	807,442	792,211	780,652
Small commercial & industrial	54,306	53,489	53,529
Large commercial & industrial	22,022	21,732	21,391
Public authorities & electric railroads	150	144	130
Total	883,920	867,576	855,702

Distribution Revenues decreased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to the impact of reduced distribution rates to reflect the lower federal income tax rate, partially offset by higher electric distribution rates in Maryland that became effective in October 2017 and June 2018 and higher electric distribution rates in the District of Columbia that became effective August 2017 and August 2018. Distribution revenues increased for the year ended December 31, 2017 compared to the same period in 2016, primarily due to higher electric distribution rates in Maryland that became effective in November 2016 and October 2017 and higher electric distribution rates in the District of Columbia that became effective August 2017. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DC PLUG and SOS administrative costs. The riders are designed to provide full and current cost 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. Revenues from regulatory required programs increased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to increases in the Maryland and District of Columbia surcharge rates and sales due to higher volumes, as well as the DC PLUG surcharge which became effective in February 2018. Revenues from regulatory required programs decreased for the year ended December 31, 2017 compared to the same period

125

Table of Contents

in 2016 primarily due to lower demand-side management program surcharge revenue due to a decrease in kWh sales and a rate decrease effective January 2017.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital 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. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 2017.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and recoveries of other taxes. Other revenue decreased for the year ended December 31, 2017 compared to the same period in 2016 due to lower pass-through revenue primarily the result of lower sales that resulted in a decrease in utility taxes that are collected by Pepco on behalf of the jurisdiction.

See Note 24 - Segment Information for the Combined Notes to Consolidated Financial Statements for the presentation of Pepco's revenue disaggregation.

The changes in Operating and maintenance expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Baseline		
ARO update[(a)]	$ 22	$ —
Merger costs[(b)]	13	(132)
BSC and PHISCO costs[(c)]	9	(24)
Uncollectible accounts expense	2	(11)
Labor, other benefits, contracting and materials	(2)	15
Write-off of construction work in progress[(d)]	—	(14)
Remeasurement of AMI-related regulatory asset[(e)]	—	(7)
Other	4	(9)
	48	(182)
Regulatory required programs	(1)	(6)
Total increase (decrease)	$ 47	$ (188)

____

(a) Reflects an increase primarily related to asbestos identified at the Buzzard Point property. See Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Decrease in 2017 primarily due to merger-related commitments for customer rate credits and charitable contributions recognized in 2016. Increase in 2018 primarily due to a deferral of accumulated merger integration costs as regulatory assets in 2017.

(c) Decrease in 2017 primarily related to merger severance and compensation costs recognized in 2016.

(d) Primarily resulting from a review of capital projects during the fourth quarter of 2016.

(e) Related to a remeasurement of a regulatory asset for legacy meters recognized in 2016.

Table of Contents

The changes in Depreciation and amortization expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Depreciation expense[(a)]	$ 14	$ 28
Regulatory asset amortization[(b)]	25	8
Regulatory required programs [(c)]	25	(10)
Total increase	$ 64	$ 26

(a) Depreciation expense increased due to ongoing capital expenditures and higher depreciation rates in Maryland effective November 2016.
(b) Regulatory asset amortization increased due to additional regulatory assets related to rate case activity.
(c) Regulatory required programs increased as a result of higher amortization of the DC PLUG regulatory asset.

Taxes other than income for the year ended December 31, 2018 compared to the same period in 2017 increased primarily due to an increase in utility taxes that are collected and passed through by Pepco (which is substantially offset in Operating revenues). Taxes other than income for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to lower utility taxes that are collected and passed through by Pepco (which is substantially offset in Operating revenues), partially offset by higher property taxes.

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the sale of land in May 2016.

Interest expense, net for the year ended December 31, 2018 compared to the same period in 2017 increased primarily due to higher outstanding debt. Interest expense, net for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the recording of interest expense for an uncertain tax position in 2016, partially offset by higher outstanding debt.

Other, net for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the September 2016 reversal of contributions in aid of construction tax gross-up reserves due to the determination that there is no legal obligation to refund customers per contract term.

Effective income tax rates for the years ended December 31, 2018, 2017, and 2016 were 5.8%, 33.9%, and 49.4%, respectively. The decrease in the effective income tax rate for the year ended December 31, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates

Table of Contents

Results of Operations—DPL

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$1,332	$1,300	$ 32	$1,277	$ 23
Purchased power and fuel expense	561	532	(29)	583	51
Revenues net of purchased power and fuel expense	771	768	3	694	74
Other operating expenses					
Operating and maintenance	344	315	(29)	441	126
Depreciation and amortization	182	167	(15)	157	(10)
Taxes other than income	56	57	1	55	(2)
Total other operating expenses	582	539	(43)	653	114
Gain on sales of assets	1	—	1	9	(9)
Operating income	190	229	(39)	50	179
Other income and (deductions)					
Interest expense, net	(58)	(51)	(7)	(50)	(1)
Other, net	10	14	(4)	13	1
Total other income and (deductions)	(48)	(37)	(11)	(37)	—
Income before income taxes	142	192	(50)	13	179
Income taxes	22	71	49	22	(49)
Net income (loss)	$120	$121	$ (1)	$(9)	$ 130

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income remained relatively consistent. The TCJA did not significantly impact Net income as the favorable tax impacts were predominately offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net income increased $130 million primarily due to merger-related costs recognized in March 2016, higher distribution base rates in Delaware that became effective July and December 2016 and higher distribution base rates in Maryland that became effective February 2017, partially offset by higher depreciation expense due to increased depreciation rates in Maryland effective February 2017. Income taxes expense included unrecognized tax benefits of $16 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the $6 million December 2017 impairment of certain transmission-related income tax regulatory assets.

Revenues Net of Purchased Power and Fuel Expense. There are certain drivers to Operating revenues that are fully offset by their impact on Purchased power and fuel expense, such as commodity and REC procurement costs and participation in customer choice programs. DPL recovers electricity and REC procurement costs from customers with a slight mark-up and natural gas costs from customers without mark-up. Therefore, fluctuations in these costs have minimal impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs do not impact the volume of deliveries or RNF, but impact Operating revenues related to supplied electricity.

Table of Contents

The changes in RNF consisted of the following:

	2018 vs. 2017 Increase (Decrease)			2017 vs. 2016 Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$11	$8	$19	$(7)	$(13)	$(20)
Volume	7	2	9	2	11	13
Distribution revenue	(20)	(6)	(26)	65	4	69
Regulatory required programs	(2)	(5)	(7)	(3)	—	(3)
Transmission revenues	6	—	6	10	—	10
Other	1	1	2	6	(1)	5
Total increase	$3	$—	$3	$73	$1	$74

Revenue Decoupling. The demand for electricity is affected by weather and customer usage. However, Operating revenues from electric distribution customers in Maryland are not affected by unseasonably warmer or colder weather because a bill stabilization adjustment (BSA) that provides for a fixed distribution charge per customer by customer class. While Operating revenues from electric distribution customers in Maryland are not impacted by abnormal weather or usage per customer, they are impacted by changes in the number of customers.

Weather. The demand for electricity and natural gas in Delaware is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and natural gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and natural gas. Conversely, mild weather reduces demand. During the year ended December 31, 2018 compared to the same period in 2017, RNF related to weather was higher due to the impact of favorable weather conditions in DPL's Delaware service territory. During the year ended December 31, 2017 compared to the same period in 2016, RNF related to weather was lower due to the impact of unfavorable weather conditions in DPL's Delaware 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 Delaware electric service territory and a 30-year period in DPL's Delaware natural gas service territory. The changes in heating and cooling degree days in DPL's Delaware service territory for the years ended December 31, 2018 and December 31, 2017 compared to same periods in 2017 and 2016, respectively, and normal weather consisted of the following:

Delaware Electric Service Territory	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	4,713	4,203	4,624	12.1 %	1.9 %
Cooling Degree-Days	1,456	1,265	1,210	15.1 %	20.3 %

	For the Years Ended December 31,			% Change	
Heating and Cooling Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,203	4,454	4,664	(5.6)%	(9.9)%

Cooling Degree-Days	1,265	1,463	1,193	(13.5)%	6.0 %

Table of Contents

Delaware Natural Gas Service Territory	For the Years Ended December 31,			% Change	
Heating Degree-Days	2018	2017	Normal	2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	4,713	4,203	4,716	12.1 %	(0.1)%

	For the Years Ended December 31,			% Change	
Heating Degree-Days	2017	2016	Normal	2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,203	4,454	4,739	(5.6)%	(11.3)%

Volume, exclusive of the effects of weather, increased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to the impact of increased average residential customer usage in DPL's Delaware service territory and overall customer growth. Volume increased for the year ended December 31, 2017 compared to the same period in 2016, primarily due to the impact of customer growth.

Electric Retail Deliveries to Delaware Customers (in GWhs)	2018	2017	% Change 2018 vs. 2017	Weather - Normal % Change	2016	% Change 2017 vs. 2016	Weather - Normal % Change
Retail Deliveries							
Residential	3,204	2,967	8.0 %	1.8 %	3,072	(3.4)%	0.9 %
Small commercial & industrial	1,344	1,317	2.1 %	— %	1,341	(1.8)%	(0.2)%
Large commercial & industrial	3,636	3,473	4.7 %	3.7 %	3,476	(0.1)%	0.9 %
Public authorities & electric railroads	33	32	3.1 %	3.4 %	35	(8.6)%	(7.1)%
Total electric retail deliveries[(a)]	8,217	7,789	5.5 %	2.3 %	7,924	(1.7)%	0.7 %

(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.

	As of December 31,		
Number of Total Electric Customers (Maryland and Delaware)	2018	2017	2016
Residential	463,670	459,389	456,181
Small commercial & industrial	61,381	60,697	60,173
Large commercial & industrial	1,406	1,400	1,411
Public authorities & electric railroads	621	629	643
Total	527,078	522,115	518,408

Natural Gas Retail Deliveries to Delaware Customers (in mmcf)	2018	2017	% Change 2018 vs.	Weather Normal %	2016	% Change 2017 vs.	Weather Normal %

			2017	change		2016	change
Retail Deliveries							
Residential	8,633	7,445	16.0 %	3.4 %	7,765	(4.1)%	1.1 %
Small commercial & industrial	4,134	3,754	10.1 %	(1.6)%	3,700	1.5 %	6.5 %
Large commercial & industrial	1,952	1,908	2.3 %	2.3 %	1,875	1.8 %	1.7 %
Transportation	6,831	6,538	4.5 %	2.3 %	6,202	5.4 %	6.3 %
Total natural gas deliveries[a]	21,550	19,645	9.7 %	2.0 %	19,542	0.5 %	3.8 %

(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.

Table of Contents

Number of Delaware Gas Customers	As of December 31, 2018	2017	2016
Residential	124,183	122,347	120,951
Small commercial & industrial	9,986	9,833	9,784
Large commercial & industrial	18	20	17
Transportation	156	154	156
Total	134,343	132,354	130,908

Distribution Revenue decreased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to reduced electric distribution rates and gas distribution rates in Delaware that were put into effect in March 2018 which reflect the impact of the lower federal income tax rate. Distribution revenue increased for the year ended December 31, 2017 compared to the same period in 2016, primarily due to higher electric distribution and natural gas distribution base rates in Delaware that became effective in July and December 2016 and higher electric distribution base rates in Maryland that became effective in February 2017. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, DE Renewable Portfolio Standards, SOS administrative costs and GCR costs. The riders are designed to provide full and current cost 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.

Transmission Revenues. Under a FERC approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, the highest daily peak load, which is updated annually in January based on the prior calendar years. Generally, increases/decreases in the highest daily peak load will result in higher/lower transmission revenue. Transmission revenue increased for the year ended December 31, 2018 compared to the same period in 2017 and for the year ended 2017 compared to the same period in 2016 due to higher rates effective June 2018 and June 2017.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues, and recoveries of other taxes.

See Note 24 - Segment Information for the Combined Notes to Consolidated Financial Statements for the presentation of DPL's revenue disaggregation.

Table of Contents

The changes in Operating and maintenance expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Baseline		
Merger costs[a]	$ 7	$ (94)
Energy efficiency merger commitments customer credits[b]	5	—
BSC and PHISCO costs[c]	4	(15)
Labor, other benefits, contracting and materials	4	8
Write-off of construction work in progress[d]	3	(3)
Uncollectible accounts expense	1	(10)
Other	6	(5)
	30	(119)
Regulatory required programs	(1)	(7)
Total increase (decrease)	$ 29	$ (126)

(a) Decrease in 2017 primarily due to merger-related commitments for customer rate credits and charitable contributions recognized in 2016. Increase in 2018 primarily due to a deferral of accumulated merger integration costs as regulatory assets in 2017.
(b) Related to EmPower Maryland energy efficiency customer credits.
(c) Decrease in 2017 primarily related to merger severance and compensation costs recognized in 2016.
(d) Decrease in 2017 primarily related to a review of capital projects in 2016.

The changes in Depreciation and amortization expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Depreciation expense[a]	$ 6	$ 14
Regulatory asset amortization [b]	18	—
Regulatory required programs[c]	(9)	(4)
Total increase	$ 15	$ 10

(a) Depreciation expense increased due to ongoing capital expenditures and higher depreciation rates in Maryland effective February 2017.
(b) Regulatory asset amortization increased due to additional regulatory assets related to rate case activity.
(c) Regulatory required programs decreased primarily due to an EmPower Maryland surcharge rate decrease effective January 2018 and 2017.

Gain on sales of assets for the year ended December 31, 2017 compared to the same period in 2016 decreased primarily due to the sale of land in July and December 2016.

Interest expense, net for the year ended December 31, 2018 compared to the same period in 2017 increased primarily due to higher outstanding debt.

Other, net for the year ended December 31, 2018 compared to the same period in 2017 decreased primarily due to lower income from AFUDC equity.

Effective income tax rates for the years ended December 31, 2018, 2017 and 2016 were 15.5%, 37.0% and 169.2%, respectively. The decrease in the effective income tax rate for the year ended December 31, 2018 compared to the same period in 2017 is primarily due to the lower federal income tax rate as a result of the TCJA. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates

132

Table of Contents

Results of Operations—ACE

	2018	2017	Favorable (unfavorable) 2018 vs. 2017 variance	2016	Favorable (unfavorable) 2017 vs. 2016 variance
Operating revenues	$1,236	$1,186	$ 50	$1,257	$ (71)
Purchased power expense	616	570	(46)	651	81
Revenues net of purchased power expense	620	616	4	606	10
Other operating expenses					
Operating and maintenance	330	307	(23)	428	121
Depreciation and amortization	136	146	10	165	19
Taxes other than income	5	6	1	7	1
Total other operating expenses	471	459	(12)	600	141
Gain on sales of assets	—	—	—	1	(1)
Operating income	149	157	(8)	7	150
Other income and (deductions)					
Interest expense, net	(64)	(61)	(3)	(62)	1
Other, net	2	7	(5)	9	(2)
Total other income and (deductions)	(62)	(54)	(8)	(53)	(1)
Income (loss) before income taxes	87	103	(16)	(46)	149
Income taxes	12	26	14	(4)	(30)
Net income (loss)	$75	$77	$ (2)	$(42)	$ 119

Year Ended December 31, 2018 Compared to Year Ended December 31, 2017. Net income remained relatively consistent. The TCJA did not significantly impact Net income as the favorable income tax impacts were predominately offset by lower revenues resulting from the pass back of the tax savings through customer rates.

Year Ended December 31, 2017 Compared to Year Ended December 31, 2016. Net Income increased by $119 million primarily due to merger-related costs recognized in March 2016 and higher electric distribution base rates effective August 2016 and October 2017 and an increase in transmission formula rate revenues, partially offset by lower customer usage. Income taxes expense included unrecognized tax benefits of $22 million for uncertain tax positions related to the deductibility of certain merger commitments in the first quarter of 2017. This decrease was offset by an increase in income taxes due to the December 2017 impairment of certain transmission-related income tax regulatory assets of $7 million.

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 and REC procurement costs and participation in customer choice programs. ACE recovers electricity and REC procurement costs from customers without mark-up. Therefore, fluctuations in these costs have no impact on RNF.

Customers have the choice to purchase electricity from competitive electric generation suppliers. Customer choice programs of supplier do not impact the volume of deliveries or RNF, but impact revenues related to supplied electricity.

Table of Contents

The changes in RNF, consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Weather	$ 12	$ (3)
Volume	14	(20)
Distribution revenue	2	40
Regulatory required programs	(23)	(24)
Transmission revenues	(4)	22
Other	3	(5)
Total increase	$ 4	$ 10

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, 2018 compared to the same period in 2017, RNF related to weather was higher due to the impact of favorable weather conditions in ACE's service territory. During the year ended December 31, 2017 compared to the same period in 2016, RNF related to weather was lower due to the impact of unfavorable winter weather conditions.

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, 2018 and December 31, 2017 compared to same periods in 2017 and 2016, respectively, and normal weather consisted of the following:

	For the Years Ended December 31,		Normal	% Change	
Heating and Cooling Degree-Days	2018	2017		2018 vs. 2017	2018 vs. Normal
Heating Degree-Days	4,523	4,206	4,666	7.5 %	(3.1)%
Cooling Degree-Days	1,535	1,228	1,135	25.0 %	35.2 %

	For the Years Ended December 31,		Normal	% Change	
Heating and Cooling Degree-Days	2017	2016		2017 vs. 2016	2017 vs. Normal
Heating Degree-Days	4,206	4,487	4,713	(6.3)%	(10.8)%
Cooling Degree-Days	1,228	1,303	1,115	(5.8)%	10.1 %

Volume, exclusive of the effects of weather, increased for the year ended December 31, 2018 compared to the same period in 2017, primarily due to higher average residential and commercial usage. Volume, exclusive of the effects of weather, decreased for the year ended December 31, 2017 compared to the same period in 2016, primarily due to lower average customer usage, partially offset by the impact of customer growth.

134

Table of Contents

Electric Retail Deliveries to Customers (in GWhs)	2018	2017	% Change 2018 vs. 2017	Weather - Normal % Change	2016	% Change 2017 vs. 2016	Weather - Normal % Change
Retail Deliveries[(a)]							
Residential	4,185	3,853	8.6 %	4.0 %	4,153	(7.2)%	(6.2)%
Small commercial & industrial	1,361	1,286	5.8 %	3.5 %	1,455	(11.6)%	(11.1)%
Large commercial & industrial	3,565	3,399	4.9 %	3.7 %	3,402	(0.1)%	0.4 %
Public authorities & electric railroads	49	47	4.3 %	4.5 %	49	(4.1)%	(4.1)%
Total retail deliveries	9,160	8,585	6.7 %	3.8 %	9,059	(5.2)%	(4.5)%

	As of December 31,		
Number of Electric Customers	2018	2017	2016
Residential	490,975	487,168	484,240
Small commercial & industrial	61,386	61,013	61,008
Large commercial & industrial	3,515	3,684	3,763
Public authorities & electric railroads	656	636	610
Total	556,532	552,501	549,621

____

(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.

Distribution Revenue increased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to higher electric distribution base rates that became effective in November 2017, partially offset by the impact of reduced distribution rates to reflect the lower federal income tax rate. Distribution revenue increased for the year ended December 31, 2017 compared to the same period in 2016, primarily due to higher electric distribution base rates that became effective in August 2016 and October 2017. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs represent revenues collected under approved riders to recover costs incurred for regulatory programs such as energy efficiency programs, Societal Benefits Charge, Transition Bonds and BGS administrative costs. The riders are designed to provide full and current cost 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. Revenues from regulatory programs decreased for the year ended December 31, 2018 compared to the same period in 2017, and for the year ended 2017 compared to the same period in 2016 due to rate decreases effective October 2017 and 2016 respectively for the ACE Transition Bonds.

Transmission Revenues. Under a FERC-approved formula, transmission revenue varies from year to year based upon fluctuations in the underlying costs, capital investments being recovered, 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. Transmission revenue decreased for the year ended December 31, 2018 compared to the same period in 2017 primarily due to the impact of the lower federal income tax rate. Transmission revenue increased for the year ended December 31, 2017 compared to the same period in 2016 due to higher rates effective June 2017 and June 2016 related to increases in transmission plant investment and operating expenses.

Other revenue includes rental revenue, revenue related to late payment charges, mutual assistance revenues and recoveries of other taxes.

See Note 24 - Segment Information of the Combined Notes to Consolidated Financial Statements for the presentation of ACE's revenue disaggregation.

Table of Contents

The changes in Operating and maintenance expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Baseline		
Labor, other benefits, contracting and materials	$ 17	$ 9
BSC and PHISCO costs[a]	10	(11)
Merger costs[b]	7	(120)
Uncollectible accounts expense[c]	(8)	—
Other	(2)	1
	24	(121)
Regulatory required programs	(1)	—
Total increase (decrease)	$ 23	$ (121)

(a) Decrease in 2017 primarily related to merger severance and compensation costs recognized in 2016.

(b) Decrease in 2017 primarily related to merger-related commitments for customer rate credits and charitable contributions recognized in 2016. Increase in 2018 primarily related to a deferral of accumulated merger integration costs as regulatory assets in 2017.

(c) ACE is allowed to recover from or refund to customers the difference between its annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. An equal and offsetting amount has been recognized in Operating revenues for the periods presented.

The changes in Depreciation and amortization expense consisted of the following:

	Increase (Decrease) 2018 vs. 2017	Increase (Decrease) 2017 vs. 2016
Depreciation expense[a]	$ 5	$ 6
Regulatory asset amortization[b]	5	(2)
Required regulatory programs[c]	(20)	(24)
Other	—	1
Total decrease	$ (10)	$ (19)

(a) Depreciation expense increased due to ongoing capital expenditures.

(b) Regulatory asset amortization increased due to additional regulatory assets related to rate case activity.

(c) Regulatory required programs decreased due to rate decreases effective October 2017 and 2016 respectively for the ACE Transition Bonds.

Other, net for the year ended December 31, 2018 compared to the same period in 2017 decreased primarily due to lower income from AFUDC equity.

Effective income tax rates were 13.8%, 25.2%, and 8.7% for the years ended December 31, 2018, 2017 and 2016, respectively. The decrease for the year ended December 31, 2018 compared to the same period in 2017 primarily due to the lower federal income tax rate as a result of the TCJA. See Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the change in effective income tax rates.

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, 2018. Exelon prior year activity is unadjusted for the effects of the

136

Table of Contents

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, 2018, 2017 and 2016. 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 $545 million in bilateral facilities with banks which have various expirations between October 2019 and April 2021 and $159 in credit facilities for project finance. 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 additional information. 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information 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 15 - Asset Retirement Obligations of 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 funds could appreciate in value. A shortfall could require that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantees or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the NDT 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. As discussed in Note 15 - Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements, Generation filed its annual decommissioning funding status report with the NRC on March 28, 2018 for shutdown reactors and reactors within five years of shutdown. As of December 31, 2018, across the alternative decommissioning approaches available, Exelon would not be required to post a parental guarantee for TMI or Oyster Creek. In the event PSEG decides to early retire Salem, Generation estimates a parental guarantee of up to $30 million from Exelon could be required for Salem, dependent upon the ultimate decommissioning approach selected.

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

Table of Contents

greatly and could be reduced by alternate decommissioning scenarios and/or reimbursement of certain costs under the DOE reimbursement agreements or future litigation, across the alternative decommissioning approaches available, if TMI were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $125 million net of taxes, dependent upon the ultimate decommissioning approach selected. In the event PSEG decides to early retire Salem and Salem were to fail to obtain the exemption, Generation estimates it could incur spent fuel management and site restoration costs over the next ten years of up to $90 million net of taxes. On October 19, 2018, the NRC granted Generation's exemption request to use the Oyster Creek NDT funds for non-radiological decommissioning costs.

On July 31, 2018, Generation entered into an agreement for the sale of Oyster Creek which is expected to occur in the second half of 2019. See Note 5 - Mergers, Acquisitions and Dispositions for additional information on the sale of Oyster Creek to Holtec.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon’s $1.15 billion of 2.50% junior subordinated notes due in 2024 (“2024 notes”) and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 (“Remarketing”). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of December 31, 2017. See Note 20 — Earnings Per Share of the Combined Notes to Consolidated Financial Statements for additional information on the issuance of common stock.

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 Note 4 — Regulatory Matters and Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information of regulatory and legal proceedings and proposed legislation.

Table of Contents

The following table provides a summary of the major items affecting Exelon’s cash flows from operations for the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2018 vs. 2017 Variance	2016	2017 vs. 2016 Variance
Net income	$2,084	$3,876	$(1,792)	$1,196	$2,680
Add (subtract):					
Non-cash operating activities[(a)]	7,580	5,445	2,135	7,714	(2,269)
Pension and non-pension postretirement benefit contributions	(383)	(405)	22	(397)	(8)
Income taxes	340	299	41	576	(277)
Changes in working capital and other noncurrent assets and liabilities[(b)]	(1,016)	(1,605)	589	(243)	(1,362)
Option premiums received (paid), net	(43)	28	(71)	(66)	94
Collateral received (posted), net	82	(158)	240	931	(1,089)
Deposit with IRS	—	—	—	(1,250)	1,250
Net cash flows provided by operations	$8,644	$7,480	$1,164	$8,461	$(981)

(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, gain on sale of assets and businesses and other non-cash charges. See Note 23 —Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements for additional information 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.

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 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy of contributing the greater of (1) $300 million until all the qualified plans are fully funded on an ABO basis, and (2) the minimum amounts under ERISA to meet minimum contribution requirements and/or avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon’s non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While other postretirement plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however, Exelon’s management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.

Table of Contents

The following table provides all registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2019:

	Qualified Pension Plans	Non-Qualified Pension Plans	Other Postretirement Benefits
Exelon	$ 301	$ 25	$ 44
Generation	135	7	13
ComEd	65	1	2
PECO	25	1	—
BGE	34	1	15
BSC	41	7	2
PHI	1	8	12
Pepco	—	2	10
DPL	—	1	—
ACE	—	—	1
PHISCO	1	5	1

To the extent interest rates decline significantly or the pension and OPEB plans earn less than the expected asset returns, annual pension contribution requirements in future years could increase. Conversely, to the extent interest rates increase significantly or the pension and OPEB plans earn greater than the expected asset returns, annual pension and OPEB contribution requirements in future years could decrease. Additionally, expected contributions could change if Exelon changes its pension or OPEB funding strategy.

Cash flows provided by operating activities for the year ended December 31, 2018, 2017 and 2016 by Registrant were as follows:

	2018	2017	2016
Exelon	$8,644	$7,480	$8,461
Generation	3,861	3,299	4,442
ComEd	1,749	1,527	2,505
PECO	739	755	829
BGE	789	821	945
Pepco	474	407	651
DPL	352	321	310
ACE	228	206	385

	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$1,132	$950	$ 888	$ 264

Changes in Registrants' cash flows from operations for 2018, 2017, and 2016 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. In addition, significant operating cash flow impacts for the Registrants for 2018, 2017 and 2016 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 2018, 2017 and 2016, Generation had net collections (payments) of counterparty cash collateral of $64 million, $(129) million and $923 million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.

- During 2018, 2017 and 2016, Generation had net (payments) collections of approximately $(43) million, $28 million and $(66) 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.

For additional information regarding changes in non-cash operating activities, see Note 23 — Supplemental Financial Information of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Investing Activities

Cash flows used in investing activities for the year ended December 31, 2018, 2017 and 2016 by Registrant were as follows:

	2018	2017	2016
Exelon	$(7,834)	$(7,971)	$(15,450)
Generation	(2,531)	(2,662)	(3,816)
ComEd	(2,097)	(2,230)	(2,685)
PECO	(840)	(597)	(797)
BGE	(950)	(875)	(910)
Pepco	(654)	(628)	(616)
DPL	(362)	(429)	(336)
ACE	(334)	(313)	(307)

	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$(1,371)	$(1,397)	$ (993)	$ (346)

Significant investing cash flow impacts for the Registrants for 2018, 2017 and 2016 were as follows:

Exelon

- During 2016, Exelon had expenditures of $6.6 billion related to the PHI merger.
- During 2016, Exelon had proceeds of $360 million as a result of early termination of direct financing leases.

Exelon and Generation

- During 2018, Exelon and Generation had expenditures of $81 million and $57 related to the acquisitions of the Everett Marine Terminal and the Handley generating station, respectively.
- During 2018, Exelon and Generation had proceeds of $85 million relating to the sale of Generation's interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution services.
- During 2017, Exelon and Generation had additional expenditures of $23 million and $178 million related to the acquisitions of ConEdison Solutions and the FitzPatrick nuclear generating station, respectively.
- During 2017, Exelon and Generation had proceeds of $218 million from sales of long-lived assets, primarily related to the sale back of turbine equipment.

Table of Contents

- During 2016, Exelon and Generation had expenditures of $235 million and $58 million related to the acquisitions of ConEdison Solutions and the FitzPatrick nuclear generating station, respectively.

Capital Expenditure Spending

Capital expenditures by Registrant for 2018, 2017 and 2016 and projected amounts for 2019 are as follows:

	Projected 2019 (a)	2018	2017	2016
Exelon(b)	$ 7,325	$7,594	$7,584	$8,553
Generation	1,950	2,242	2,259	3,078
ComEd	1,875	2,126	2,250	2,734
PECO	975	849	732	686
BGE	1,100	959	882	934
Pepco	725	656	628	586
DPL	350	364	428	349
ACE	300	335	312	311

		Successor			Predecessor
	Projected 2019 (a)	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI(c)	$ 1,375	$1,375	$1,396	$ 1,008	$ 273

(a) Total projected capital expenditures do not include adjustments for non-cash activity. Amounts are rounded to the nearest $25 million.
(b) Includes corporate operations, BSC and PHISCO.
(c) Includes PHISCO.

Projected capital expenditures and other investments are subject to periodic review and revision to reflect changes in economic conditions and other factors.

Generation

Approximately 43% and 8% of the projected 2019 capital expenditures at Generation are for the acquisition of nuclear fuel, and the construction of new natural gas plants and solar facilities, 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 it will fund capital expenditures with internally generated funds and borrowings.

ComEd, PECO, BGE, Pepco, DPL and ACE

Projected 2019 capital expenditures at the Utility Registrants are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as the Utility Registrants' construction commitments under PJM’s RTEP.

The Utility Registrants as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments could require the Utility Registrants to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. In 2010, NERC provided guidance to transmission owners that recommended the Utility Registrants perform assessments of their transmission lines. ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd and PECO 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 and PECO’s forecasted 2019 capital expenditures above reflect capital spending for remediation to be completed through 2019. BGE, DPL and ACE are complete with their assessments and Pepco has substantially completed its assessment and thus do not expect significant capital expenditures related to this guidance in 2019.

Table of Contents

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.

Cash Flows from Financing Activities

Cash flows (used in) provided by financing activities for the year ended December 31, 2018, 2017 and 2016 by Registrant were as follows:

	2018	2017	2016
Exelon	$(219)	$767	$1,191
Generation	(981)	(531)	(734)
ComEd	534	789	169
PECO	(39)	50	(263)
BGE	156	22	(21)
Pepco	193	219	—
DPL	32	64	67
ACE	105	5	22

	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$330	$306	$ (7)	$ 372

Table of Contents

Debt

See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' debt issuances and retirements. Debt activity for 2018, 2017 and 2016 by Registrant was as follows:

During 2018, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing[(a)]	3.72 %	March 31, 2019	$ 4	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Energy Efficiency Project Financing[(a)]	3.17 %	January 31, 2019	$ 1	Funding to install energy conservation measures in Brooklyn, NY.
Generation	Energy Efficiency Project Financing[(a)]	2.61 %	September 30, 2018	$ 5	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing[(a)]	4.17 %	January 31, 2019	$ 1	Funding to install energy conservation measures for the General Services Administration Philadelphia project.
Generation	Energy Efficiency Project Financing[(a)]	4.26 %	May 31, 2019	$ 3	Funding to install energy conservation measures for the National Institutes of Health Multi-Buildings Phase II project.
ComEd	First Mortgage Bonds, Series 124	4.00 %	March 1, 2048	$ 800	Refinance one series of maturing first mortgage bonds, to repay a portion of ComEd's outstanding commercial paper obligations and to fund general corporate purposes
ComEd	First Mortgage Bonds, Series 125	3.70 %	August 15, 2028	$ 550	Repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.90 %	March 1, 2048	$ 325	Refinance a portion of maturing mortgage bonds.
PECO	Loan Agreement	2.00 %	June 20, 2023	$ 50	Funding to implement Electric Long-term Infrastructure Improvement Plan
PECO	First and Refunding Mortgage Bonds	3.90 %	March 1, 2048	$ 325	Satisfy short-term borrowings from the Exelon intercompany money pool and for general corporate purposes.
BGE	Senior Notes	4.25 %	September 15, 2048	$ 300	Repay commercial paper obligations and for general corporate purposes.
Pepco	First Mortgage Bonds	4.27 %	June 15, 2048	$ 100	Repay outstanding commercial paper and for general corporate purposes.
Pepco	First Mortgage Bonds	4.31 %	November 1, 2048	$ 100	Repay outstanding commercial paper and for general corporate purposes.
DPL	First Mortgage Bonds	4.27 %	June 15, 2048	$ 200	Repay outstanding commercial paper and for general corporate purposes.
ACE	First Mortgage Bonds	4.00 %	October 15, 2028	$ 350	Refinance ACE's 7.75% First Mortgage Bonds due November 15, 2018, reduce short-term borrowings and for general corporate purposes.

____

(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

Table of Contents

During 2017, the following long term debt was issued:

Company	Type	Interest Rate		Maturity	Amount	Use of Proceeds
Exelon Corporate	Junior Subordinated Notes	3.50	%	June 1, 2022	$ 1,150	Refinance Exelon's Junior Subordinated Notes issued in June 2014.
Generation	Albany Green Energy Project Financing[(a)]	LIBOR + 1.25%		November 17, 2017	$ 14	Albany Green Energy biomass generation development.
Generation	Energy Efficiency Project Financing[(a)]	3.90	%	February 1, 2018	$ 19	Funding to install energy conservation measures for the Naval Station Great Lakes project.
Generation	Energy Efficiency Project Financing[(a)]	3.72	%	May 1, 2018	$ 5	Funding to install energy conservation measures for the Smithsonian Zoo project.
Generation	Energy Efficiency Project Financing[(a)]	2.61	%	September 30, 2018	$ 13	Funding to install energy conservation measures for the Pensacola project.
Generation	Energy Efficiency Project Financing[(a)]	3.53	%	April 1, 2019	$ 8	Funding to install energy conservation measures for the State Department project.
Generation	Senior Notes	2.95	%	January 15, 2020	$ 250	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	Senior Notes	3.40	%	March 15, 2020	$ 500	Repay outstanding commercial paper obligations and for general corporate purposes.
Generation	ExGen Texas Power Nonrecourse Debt[(b)(c)]	LIBOR + 4.75%		September 18, 2021	$ 6	General corporate purposes.
Generation	ExGen Renewables IV, Nonrecourse Debt[(b)]	LIBOR + 3.00%		November 30, 2024	$ 850	General corporate purposes.
ComEd	First Mortgage Bonds, Series 122	2.95	%	August 15, 2027	$ 350	Refinance maturing mortgage bonds, repay a portion of ComEd’s outstanding commercial paper obligations and for general corporate purposes
ComEd	First Mortgage Bonds, Series 123	3.75	%	August 15, 2047	$ 650	Refinance maturing mortgage bonds, repay a portion of ComEd’s outstanding commercial paper obligations and for general corporate purposes.
PECO	First and Refunding Mortgage Bonds	3.70	%	September 15, 2047	$ 325	General corporate purposes.
BGE	Senior Notes	3.75	%	August 15, 2047	$ 300	Redeem $250 million in principal amount of the 6.20% Deferrable Interest Subordinated Debentures due October 15, 2043 issued by BGE's affiliate BGE Capital Trust II, repay commercial paper obligations and for general

						corporate purposes.
Pepco	Energy Efficiency Project Financing[(a)]	3.30	%	December 15, 2017	$ 2	Funding to install energy conservation measures for the DOE Germantown project.
Pepco	First Mortgage Bonds	4.15	%	March 15, 2043	$ 200	Funding to repay outstanding commercial paper and for general corporate purposes.

(a) For Energy Efficiency Project Financing, the maturity dates represent the expected date of project completion, upon which the respective customer assumes the outstanding debt.

Table of Contents

(b) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

(c) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. See Note 5 — Mergers, Acquisitions and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information.

During 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	SolGen Nonrecourse Debt[(a)]	3.93	%	September 30, 2036	$ 150	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.
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.

Table of Contents

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 for general corporate purposes.

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information 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.

During 2018, 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	$ 6
Generation	Naval Station Great Lakes Project Financing	3.90%	June 30, 2018	$ 41
Generation	Smithsonian Zoo Project Financing	3.72%	March 31, 2019	$ 1
Generation	Pensacola Project Financing	2.61%	September 30, 2018	$ 21
Generation	Fort Detrick Project Financing	3.55%	June 30, 2019	$ 19
Generation	Holyoke Nonrecourse Debt[(a)]	5.25%	December 31, 2031	$ 1
Generation	SolGen Nonrecourse Debt[(a)]	3.93%	September 30, 2036	$ 10
Generation	Antelope Valley DOE Nonrecourse Debt[(a)]	2.29% - 3.56%	January 5, 2037	$ 22
Generation	Continental Wind Nonrecourse Debt[(a)]	6.00%	February 28, 2033	$ 33
Generation	Renewable Power Generation Nonrecourse Debt[(a)]	4.11%	March 31, 2035	$ 11
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 4
Generation	ExGen Renewables IV Nonrecourse Debt	3mL+300 bps	November 30, 2024	$ 16
Generation	NUKEM	3.15% - 3.35%	2018 - 2020	$ 43
ComEd	First Mortgage Bonds	5.80%	March 15, 2018	$ 700
ComEd	Notes	6.95%	July 15, 2018	$ 140
PECO	First Mortgage Bonds	5.35%	March 1, 2018	$ 500
DPL	Medium Term Notes, Unsecured	6.81%	January 9, 2018	$ 4
Pepco	Notes	3.30%	August 31, 2018	$ 5
Pepco	Third Party Financing	7.28-7.99%	2021 - 2023	$ 1
ACE	First Mortgage Bonds	7.75%	November 15, 2018	$ 250
ACE	Transition Bonds	5.05% - 5.55%	2020 - 2023	$ 31

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

Table of Contents

During 2017, 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	$ 24
Exelon Corporate	Senior Notes	1.55%	June 9, 2017	$ 550
Generation	Senior Notes - Exelon Wind	2.00%	July 31, 2017	$ 1
Generation	CEU Upstream Nonrecourse Debt[(a)]	LIBOR + 2.25%	January 14, 2019	$ 6
Generation	SolGen Nonrecourse Debt[(a)]	3.93%	September 30, 2036	$ 2
Generation	Antelope Valley DOE Nonrecourse Debt[(a)]	2.29% - 3.56%	January 5, 2037	$ 22
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	Continental Wind Nonrecourse Debt[(a)]	6.00%	February 28, 2033	$ 31
Generation	PES - PGOV Notes Payable	6.70-7.60%	2017 - 2018	$ 1
Generation	ExGen Texas Power Nonrecourse Debt[(a)(b)]	LIBOR + 4.75%	September 18, 2021	$ 665
Generation	Renewable Power Generation Nonrecourse Debt[(a)]	4.11%	March 31, 2035	$ 14
Generation	NUKEM	3.25% - 3.35%	June 30, 2018	$ 23
Generation	ExGen Renewables I, Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 233
Generation	Senior Notes	6.20%	October 1, 2017	$ 700
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 212
ComEd	First Mortgage Bonds	6.15%	September 15, 2017	$ 425
BGE	Rate Stabilization Bonds	5.82%	April 1, 2017	$ 41
BGE	Capital Trust Preferred Securities	6.20%	October 15, 2043	$ 258
PHI	Senior Notes	6.13%	June 1, 2017	$ 81
DPL	Medium Term Notes, Unsecured	7.56% - 7.58%	February 1, 2017	$ 14
DPL	Variable Rate Demand Bonds	Variable	October 1, 2017	$ 26
Pepco	Third Party Financing	6.97% - 7.99%	2018 - 2022	$ 1
ACE	Transition Bonds	5.05% - 5.55%	2020 - 2023	$ 35

(a) See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

(b) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. See Note 5 — Mergers, Acquisitions and Dispositions for additional information.

Table of Contents

During 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	Antelope Valley 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]	LIBOR + 2.25%	January 14, 2019	$ 46
Generation	ExGen Texas Power Nonrecourse Debt[a][b]	5.00%	September 18, 2021	$ 7
Generation	Sacramento Solar Nonrecourse Debt	LIBOR + 2.25%	December 31, 2030	$ 33
Generation	Clean Horizons Nonrecourse Debt	LIBOR + 2.25%	September 7, 2030	$ 32
Generation	ExGen Renewables I, Nonrecourse Debt	LIBOR + 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
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	Rate Stabilization 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of nonrecourse debt.

(b) As a result of the bankruptcy filing for EGTP on November 7, 2017, the nonrecourse debt was deconsolidated from Exelon's and Generation's consolidated financial statements. See Note 5 — Mergers, Acquisitions and Dispositions for additional information.

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.

Table of Contents

Dividends

Cash dividend payments and distributions for the year ended December 31, 2018, 2017 and 2016 by Registrant were as follows:

	2018	2017	2016
Exelon	$1,332	$1,236	$1,166
Generation	1,001	659	922
ComEd	459	422	369
PECO	306	288	277
BGE[(a)]	209	198	187
Pepco	169	133	136
DPL	96	112	54
ACE	59	68	63

	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$326	$311	$ 273	$ —

(a) Includes dividends paid on BGE's preference stock during 2016.

Quarterly dividends declared by the Exelon Board of Directors during the year ended December 31, 2018 and for the first quarter of 2019 were as follows:

Period	Declaration Date	Shareholder of Record Date	Dividend Payable Date	Cash per Share[(a)]
First Quarter 2018	January 30, 2018	February 15, 2018	March 9, 2018	$ 0.3450
Second Quarter 2018	May 1, 2018	May 15, 2018	June 8, 2018	$ 0.3450
Third Quarter 2018	July 24, 2018	August 15, 2018	September 10, 2018	$ 0.3450
Fourth Quarter 2018	September 24, 2018	November 15, 2018	December 1, 2018	$ 0.3450
First Quarter 2019	February 5, 2019	February 20, 2019	March 8, 2019	$ 0.3625

(a) Exelon's Board of Directors approved an updated dividend policy providing an increase of 5% each year for the period covering 2018 through 2020, beginning with the March 2018 dividend.

Short-Term Borrowings

Short-term borrowings incurred (repaid) during 2018, 2017 and 2016 by Registrant were as follows:

	2018	2017	2016
Exelon	$(338)	$(261)	$(353)
Generation	—	(620)	620
ComEd	—	—	(294)
BGE	(42)	32	(165)
Pepco	14	3	(41)
DPL	(216)	216	(105)
ACE	(94)	108	(5)

Table of Contents

	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$(296)	$328	$ (515)	$ (121)

Retirement of Long-Term Debt to Financing Affiliates

On August 28, 2017, BGE redeemed all of the outstanding shares of BGE Capital Trust II 6.20% Preferred Securities.

Contributions from Parent/Member

Contributions from Parent/Member (Exelon) during 2018, 2017 and 2016 by Registrant were as follows:

	2018	2017	2016
Generation	$155	$102	$142
ComEd[(a)(b)]	500	672	473
PECO[(b)]	89	16	18
BGE[(b)]	109	184	61
Pepco[(c)]	166	161	187
DPL[(c)]	150	—	152
ACE[(c)]	67	—	139

	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$385	$758	$ 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 PHI 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, 2018, BGE no longer has any preferred stock outstanding.

Other

For the year ended December 31, 2018, other financing activities primarily consists of debt issuance costs. See Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements' for additional information.

151

Table of Contents

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 $9.7 billion (including bilateral credit facilities and credit facilities for project finance) in aggregate total commitments of which $8.0 billion was available as of December 31, 2018, and of which no financial institution has more than 7% of the aggregate commitments for the Registrants. The Registrants had access to the commercial paper market during 2018 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 additional 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, 2018, it would have been required to provide incremental collateral of $2.1 billion to meet collateral obligations for derivatives, non-derivatives, normal purchases and normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements, which is well within the $4.1 billion of available credit capacity of its revolver.

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, 2018 and available credit facility capacity prior to any incremental collateral at December 31, 2018:

	PJM Credit Policy Collateral	Other Incremental Collateral Required[(a)]	Available Credit Facility Capacity Prior to Any Incremental Collateral
ComEd	$ 9	$ —	$ 998
PECO	—	39	600
BGE	12	69	599
Pepco	11	—	292
DPL	5	11	299
ACE	—	—	300

(a) Represents incremental collateral related to natural gas procurement contracts.

Exelon Credit Facilities

Exelon Corporate, ComEd, BGE, Pepco, DPL and ACE 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 Corporate meets its short-term liquidity requirements primarily through the issuance of short-term notes and the Exelon intercompany money pool. 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' credit facilities and short term borrowing activity.

152

Table of Contents

Other Credit Matters

Capital Structure. At December 31, 2018, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Long-term debt	51 %	32 %	44 %	44 %	46 %	40 %	49 %	50 %	48 %
Long-term debt to affiliates[(a)]	1 %	4 %	1 %	3 %	— %	— %	— %	— %	— %
Common equity	47 %	— %	55 %	53 %	53 %	—	50 %	50 %	46 %
Member's equity	— %	64 %	— %	— %	— %	59 %	—	—	—
Commercial paper and notes payable	1 %	— %	—	— %	1 %	1 %	1 %	— %	6 %

(a) Includes approximately \$390 million, \$205 million and \$184 million owed to unconsolidated affiliates of Exelon, ComEd, and PECO respectively. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd and PECO. 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 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

Table of Contents

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, 2018, are presented in the following tables:

Exelon Intercompany Money Pool	For the Year Ended December 31, 2018		As of December 31, 2018
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Exelon Corporate	$ 674	$ —	$ 216
Generation	227	(389)	(100)
PECO	285	(420)	—
BSC	—	(403)	(173)
PHI Corporate	—	(35)	—
PCI	57	(1)	57

PHI Intercompany Money Pool	For the Year Ended December 31, 2018		As of December 31, 2018
Contributed (borrowed)	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
PHI Corporate	$ 1	$ —	$ 1
PHISCO	34	—	3

Investments in NDT 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 15 — Asset Retirement Obligations of the Combined Notes to Consolidated Financial Statements for additional information regarding the trust funds, the NRC’s minimum funding requirements and related liquidity ramifications.

Shelf Registration Statements. Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in August 2019. The ability of each Registrant to sell securities off the shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. 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[a]		
	Commission	Expiration Date	Amount	Commission	Expiration Date	Amount [c]
ComEd[b]	FERC	December 31, 2019	$ 2,500	ICC	2019 & 2021	$ 1,533
PECO	FERC	December 31, 2019	1,500	PAPUC	December 31, 2021	1,900
BGE	FERC	December 31, 2019	700	MDPSC	N/A	400
Pepco	FERC	December 31, 2019	500	MDPSC / DCPSC	December 31, 2020	400
DPL	FERC	December 31, 2019	500	MDPSC / DPSC	December 31, 2020	150
ACE	NJBPU	December 31, 2019	350	NJBPU	December 31, 2019	—

____

(a) Generation currently has blanket financing authority it received from FERC in connection with its market-based rate authority.

Table of Contents

(b) ComEd had $440 million available in long-term debt refinancing authority and $1,093 million available in new money long-term debt financing authority from the ICC as of December 31, 2018 and has an expiration date of June 1, 2019 and August 1, 2021, respectively.
(c) ACE is currently in the process of requesting its long-term debt financing authority.

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.

- ComEd is subject to restrictions 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.
- PECO is subject to restrictions 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.
- BGE is subject to restrictions established by the MDPSC that prohibit BGE 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.
- Pepco, DPL and ACE are subject to certain dividend restrictions established by settlements approved in the District of Columbia, Maryland, Delaware, and New Jersey. 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 DCPSC, MDPSC, DPSC, and NJBPU 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. ACE is also subject to a dividend restriction which requires ACE to 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%.

At December 31, 2018, Exelon had retained earnings of $14,766 million, including Generation’s undistributed earnings of $3,724 million, ComEd’s retained earnings of $1,337 million consisting of retained earnings appropriated for future dividends of $2,976 million partially offset by $1,639 million of unappropriated retained deficit, PECO’s retained earnings of $1,242 million, BGE’s retained earnings $1,640 million, and PHI's undistributed earnings of $62 million. See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Table of Contents

Contractual Obligations and Off-Balance Sheet Arrangements

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2018 under existing contractual obligations, including payments due by period. See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within			
	Total	2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt[a]	$35,265	$1,328	$5,033	$3,933	$ 24,971
Interest payments on long-term debt[b]	22,840	1,446	2,689	2,372	16,333
Capital leases	36	21	6	1	8
Operating leases[c][d]	1,378	140	292	223	723
Purchase power obligations[e]	1,121	365	484	98	174
Fuel purchase agreements[f]	5,984	1,235	2,078	1,269	1,402
Electric supply procurement[f]	2,836	1,828	1,008	—	—
AEC purchase commitments[f]	2	1	1	—	—
Curtailment services commitments[f]	129	29	74	26	—
Long-term renewable energy and REC commitments[g]	1,838	137	265	274	1,162
Other purchase obligations[h]	6,626	4,676	1,323	247	380
DC PLUG obligation[i]	160	30	60	60	10
Construction commitments[j]	21	21	—	—	—
PJM regional transmission expansion commitments[k]	396	141	237	18	—
SNF obligation[l]	1,171	—	—	—	1,171
ZEC commitments[m]	1,404	168	337	332	567
Pension contributions[n]	2,276	301	616	752	607
Total contractual obligations	$83,483	$11,867	$14,503	$9,605	$ 47,508

____

(a) Includes $390 million due after 2024 to ComEd and PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 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, 2018. Includes estimated interest payments due to ComEd and PECO financing trusts.

(c) Includes amounts related to shared use land arrangements.

(d) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations.

(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, 2018. 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. Contained within Purchase power obligations are Net Capacity Purchases of $126 million, $56 million, $35 million, $26 million, $20 million and $155 million for 2019, 2020, 2021, 2022, 2023 and thereafter, respectively.

(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 earliest and maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.

(h)

Represents the future estimated value at December 31, 2018 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.

Table of Contents

(i) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 4 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(j) Represents commitments for Generation's ongoing investments in new natural gas generation construction. As of December 31, 2018, the commitments relate to the construction of a new dual fuel, natural peaking facility in Massachusetts. Achievement of commercial operation related to this project is expected in 2019.

(k) Under their operating agreements with PJM, ComEd, PECO, BGE, DPL and ACE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd, PECO, BGE, DPL and ACE's expected portion of the costs to pay for the completion of the required construction projects.

(l) See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding SNF obligations.

(m) Annual ZEC commitment amounts will be published by the IPA each May prior to the start of the subsequent planning year. Amounts presented in the table represent management's estimate of ComEd's obligation based on forward energy prices and load forecasts. ComEd is permitted to recover its ZEC costs from retail customers with no mark-up.

(n) These amounts represent Exelon's expected contributions to its qualified pension plans. The projected contributions reflect a funding strategy of contributing the greater of $300 million until all the qualified plans are fully funded on an ABO basis, and the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. These amounts represent estimates that are based on assumptions that are subject to change. Qualified pension contributions for years after 2024 are not included. See Note 16 — Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding estimated future pension benefit payments.

Generation

		Payment due within			
	Total	2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt	$8,745	$899	$2,103	$1,023	$ 4,720
Interest payments on long-term debt[a]	4,333	354	592	483	2,904
Capital leases	14	7	6	1	—
Operating leases[b][c]	763	33	92	93	545
Purchase power obligations[d]	1,121	365	484	98	174
Fuel purchase agreements[e]	4,931	1,013	1,759	1,078	1,081
Other purchase obligations[f]	1,742	1,114	224	98	306
Construction commitments[g]	21	21	—	—	—
SNF obligation[h]	1,171	—	—	—	1,171
Total contractual obligations	$22,841	$3,806	$5,260	$2,874	$ 10,901

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 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, 2018.

(b) Includes amounts related to shared use land arrangements.

(c) Excludes Generation's contingent operating lease payments associated with contracted generation agreements. These amounts are included within purchase power obligations.

(d) Purchase power obligations include contingent operating lease payments associated with contracted generation agreements. Amounts represent Generation's expected payments under these arrangements at December 31, 2018. 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. Contained within Purchase power obligations are Net Capacity Purchases of $126 million, $56 million, $35 million, $26 million, $20 million and $155 million for 2019, 2020, 2021, 2022, 2023 and thereafter, respectively.

(e) Primarily represents commitments to purchase fuel supplies for nuclear and fossil generation, including those related to CENG.

(f) Represents the future estimated value at December 31, 2018 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.

(g) Represents commitments for Generation's ongoing investments in new natural gas generation construction. As of December 31, 2018, the commitments relate to the construction of a new dual fuel, natural peaking facility in Massachusetts. Achievement of commercial operation related to this project is expected in 2019.

Table of Contents

(h) See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding SNF obligations.

ComEd

	Payment due within				
	Total	2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt[a]	$8,385	$300	$850	$—	$ 7,235
Interest payments on long-term debt[b]	6,512	339	646	614	4,913
Capital leases	8	—	—	—	8
Operating leases[c]	23	7	9	7	—
Electric supply procurement	650	419	231	—	—
Long-term renewable energy and REC commitments[d]	1,497	106	203	212	976
Other purchase obligations[e]	1,109	1,050	55	2	2
PJM regional transmission expansion commitments[f]	176	40	136	—	—
ZEC commitments[g]	1,404	168	337	332	567
Total contractual obligations	$19,764	$2,429	$2,467	$1,167	$ 13,701

(a) Includes $206 million due after 2024 to a ComEd financing trust.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 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, 2018. Includes estimated interest payments due to the ComEd financing trust.

(c) Includes amounts related to shared use land arrangements.

(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 and earliest settlements with suppliers for renewable energy and RECs under the existing contract terms.

(e) Represents the future estimated value at December 31, 2018 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.

(g) Annual ZEC commitment amounts will be published by the IPA each May prior to the start of the subsequent planning year. Amounts presented in the table represent management's estimate of ComEd's obligation based on forward energy prices and load forecasts. ComEd is permitted to recover its ZEC costs from retail customers with no mark-up.

Table of Contents

PECO

	Total	Payment due within 2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt[(a)]	$3,309	$—	$300	$400	$ 2,609
Interest payments on long-term debt[(b)]	2,562	131	261	242	1,928
Operating leases[(c)(d)]	25	5	10	10	—
Fuel purchase agreements[(e)]	335	116	151	33	35
Electric supply procurement[(e)]	530	453	77	—	—
AEC purchase commitments[(e)]	4	2	2	—	—
Other purchase obligations[(f)]	668	501	156	10	1
PJM regional transmission expansion commitments[(g)]	54	27	18	9	—
Total contractual obligations	$7,487	$1,235	$975	$704	$ 4,573

(a) Includes $184 million due after 2024 to PECO financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(c) Includes amounts related to shared use land arrangements.

(d) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, PECO has excluded these payments from the remaining years as such amounts would not be meaningful. PECO's average annual obligation for these arrangements, included in each of the years 2019 - 2023, was $5 million. Also includes amounts related to shared use land arrangements.

(e) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs.

(f) Represents the future estimated value at December 31, 2018 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.

(g) 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.

BGE

	Total	Payment due within 2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt	$2,900	$—	$300	$550	$ 2,050
Interest payments on long-term debt[(a)]	1,971	113	225	191	1,442
Operating leases[(b)(c)(d)(e)]	143	35	68	21	19
Fuel purchase agreements[(f)]	434	76	107	94	157
Electric supply procurement[(f)]	1,070	670	400	—	—
Curtailment services commitments[(f)]	61	10	38	13	—
Other purchase obligations[(g)]	584	528	50	2	4
PJM regional transmission expansion commitments[(h)]	89	35	54	—	—
Total contractual obligations	$7,252	$1,467	$1,242	$871	$ 3,672

(a)

Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(b) Includes amounts related to shared use land arrangements.

Table of Contents

(c) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, BGE has excluded these payments from the remaining years as such amounts would not be meaningful. BGE's average annual obligation for these arrangements, included in each of the years 2019 - 2023, was $1 million. Also includes amounts related to shared use land arrangements.

(d) Includes all future lease payments on a 99-year real estate lease that expires in 2106.

(e) The BGE table above includes minimum future lease payments associated with a 6-year lease for the Baltimore City conduit system that became effective during the fourth quarter of 2016. BGE's total commitments under the lease agreement are $26 million, $28 million, $28 million, and $14 million related to years 2019 - 2022, respectively.

(f) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and curtailment services.

(g) Represents the future estimated value at December 31, 2018 of the cash flows associated with all contracts, both cancellable and non-cancellable, entered into between the BGE 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.

(h) 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.

PHI

		Payment due within			
	Total	2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt	$5,622	$111	$281	$810	$ 4,420
Interest payments on long-term debt[(a)]	4,192	260	512	476	2,944
Capital leases	14	14	—	—	—
Operating leases[(b)]	377	48	89	81	159
Fuel purchase agreements[(c)]	284	30	61	64	129
Long-term renewable energy and REC commitments[(c)]	341	31	62	62	186
Electric supply procurement[(c)]	1,635	993	642	—	—
Curtailment services commitments[(c)]	68	19	36	13	—
Other purchase obligations[(d)]	1,396	893	437	34	32
DC PLUG obligation[(e)]	160	30	60	60	10
PJM regional transmission expansion commitments[(f)]	77	39	29	9	—
Total contractual obligations	$14,166	$2,468	$2,209	$1,609	$ 7,880

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(b) Includes amounts related to shared use land arrangements.

(c) 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.

(d) Represents the future estimated value at December 31, 2018 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) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 4 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

(f)

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.

Table of Contents

Pepco

	Total	Payment due within 2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt	$2,737	$1	$1	$310	$ 2,425
Interest payments on long-term debt[a]	2,488	138	276	256	1,818
Capital leases	14	14	—	—	—
Operating leases[b]	86	11	19	16	40
Electric supply procurement[c]	663	407	256	—	—
Curtailment services commitments[c]	33	4	20	9	—
Other purchase obligations[d]	908	509	337	31	31
DC PLUG obligation[e]	160	30	60	60	10
Total contractual obligations	$7,089	$1,114	$969	$682	$ 4,324

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Includes amounts related to shared use land arrangements.
(c) Represents commitments to purchase procure electric supply and curtailment services.
(d) Represents the future estimated value at December 31, 2018 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) Related to DC PLUG project costs for assets funded by the District of Columbia for which the District of Columbia has assessed a charge on Pepco. Pepco will recover this charge from customers through a volumetric distribution rider. See Note 4 — Regulatory Matters of Combined Notes to Consolidated Financial Statements for additional information.

DPL

	Total	Payment due within 2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt	$1,504	$91	$—	$500	$ 913
Interest payments on long-term debt[a]	1,050	57	113	111	769
Operating leases[b]	96	14	25	22	35
Fuel purchase agreements[c]	284	30	61	64	129
Long-term renewable energy and associated REC commitments[c]	341	31	62	62	186
Electric supply procurement[c]	458	282	176	—	—
Curtailment services commitments[c]	31	12	15	4	—
Other purchase obligations[d]	266	187	77	1	1
PJM regional transmission expansion commitments[e]	9	3	3	3	—
Total contractual obligations	$4,039	$707	$532	$767	$ 2,033

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(b) Includes amounts related to shared use land arrangements.
(c)

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.

(d) Represents the future estimated value at December 31, 2018 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.

Table of Contents

(e) 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.

ACE

	Total	Payment due within 2019	2020 - 2021	2022 - 2023	Due 2024 and beyond
Long-term debt	$1,196	$18	$280	$ —	$ 898
Interest payments on long-term debt [a]	465	52	95	81	237
Operating leases[b]	32	7	11	9	5
Electric supply procurement [c]	514	304	210	—	—
Curtailment services commitments [c]	4	3	1	—	—
Other purchase obligations [d]	177	160	16	1	—
PJM regional transmission expansion commitments [e]	68	36	26	6	—
Total contractual obligations	$2,456	$580	$639	$ 97	$ 1,140

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2018 and do not reflect anticipated future refinancing, early redemptions or debt issuances.

(b) Includes amounts related to shared use land arrangements.

(c) Represents commitments to procure electric supply and curtailment services.

(d) Represents the future estimated value at December 31, 2018 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, 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 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 14 — Income Taxes of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements.
- operating leases and rate relief commitments, see Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Note 15 — Asset Retirement Obligations and Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

Table of Contents

- variable interest entities, see Note 2 — Variable Interest Entities of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 22 — 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 total amount of energy Exelon generates and purchases differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in commodity prices. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel and other commodities.

Generation

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 commodity price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as derivative contracts, including swaps, futures, forwards and options, with approved counterparties to hedge anticipated exposures. Generation uses derivative instruments as economic hedges to mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges will occur during 2019 through 2021.

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 price risk for Exelon's expected generation, typically on a ratable basis over three-year periods. As of December 31, 2018, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92%, 56%-59% and 32%-35% for 2019, 2020 and 2021, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted generating facilities based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including Generation's sales to ComEd, PECO and BGE to serve their retail load.

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 economic hedge portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2018 market conditions and hedged position would be decreases in pre-tax net income of approximately $57 million, $383 million and $618 million, respectively, for 2019, 2020 and 2021. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation actively manages its portfolio to mitigate market price risk exposure for its unhedged position. Actual

Table of Contents

results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Proprietary Trading Activities

Proprietary trading portfolio activity for the year ended December 31, 2018, resulted in pre-tax gains of $42 million due to net mark-to-market gains of $17 million and realized gains of $25 million. 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 purchased power and fuel expense. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

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 62% of Generation's uranium concentrate requirements from 2019 through 2023 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 financial statements.

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.

ComEd has block energy contracts to procure electric supply that are executed through a competitive procurement process, which is further discussed in Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. The block energy contracts 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. ComEd does not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

PECO, BGE, Pepco, DPL and ACE

PECO, BGE, Pepco, DPL and ACE have contracts to procure electric supply that are executed through a competitive procurement process, which are further discussed in Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements. PECO, BGE, Pepco, DPL and ACE have 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. Other full requirements contracts are not derivatives.

PECO, BGE and DPL have also executed 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 their long-term price risk in the natural gas market. The hedging programs for natural gas procurement have no direct impact on their financial statements.

164

Table of Contents

PECO, BGE, Pepco, DPL and ACE do not execute derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities

The following table detailing Exelon's, Generation's and ComEd's trading and non-trading marketing activities are 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 and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2016 to December 31, 2018. 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 NPNS contracts and does not segregate proprietary trading activity. See Note 12 — 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, 2018 and 2017.

	Exelon	Generation	ComEd
Total mark-to-market energy contract net assets (liabilities) at December 31, 2016[a]	$ 719	$ 977	$ (258)
Total change in fair value during 2017 of contracts recorded in result of operations	110	110	—
Reclassification to realized at settlement of contracts recorded in results of operations	(273)	(273)	—
Changes in fair value—recorded through regulatory assets and liabilities[b]	(1)	—	2
Changes in allocated collateral	140	137	—
Net option premium received	(28)	(28)	—
Option premium amortization	(7)	(7)	—
Upfront payments and amortizations[c]	(24)	(24)	—
Other miscellaneous[d]	31	31	—
Total mark-to-market energy contract net assets (liabilities) at December 31, 2017[a]	667	923	(256)
Total change in fair value during 2018 of contracts recorded in result of operations	270	270	—
Reclassification to realized at settlement of contracts recorded in results of operations	(570)	(570)	—
Contracts received at acquisition date[e]	(19)	(19)	—
Changes in fair value—recorded through regulatory assets and liabilities[b]	8	—	7
Changes in allocated collateral	(110)	(109)	—
Net option premium paid	43	43	—
Option premium amortization	(10)	(10)	—
Upfront payments and amortizations[c]	20	20	—
Total mark-to-market energy contract net assets (liabilities) at December 31, 2018[a]	$ 299	$ 548	$ (249)

(a) Amounts are shown net of collateral paid to and received from counterparties.

(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2017 and 2018, ComEd recorded a regulatory liability of $256 million and $249 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. ComEd recorded $18 million of decreases in fair value and an increase for realized losses due to settlements of $20 million in purchased power expense associated with floating-to-fixed energy swap suppliers for the year ended December 31, 2017. ComEd recorded $24 million of decreases in fair value

165

Table of Contents

and realized losses due to settlements of $17 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2018.

(c) Includes derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums, and the associated amortizations.

(d) As a result of the bankruptcy filing for EGTP on November 7, 2017, the net mark-to-market commodity contracts were deconsolidated from Exelon's and Generation's consolidated financial statements.

(e) Includes fair value from contracts received at acquisition of the Everett Marine Terminal.

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 11 — Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2019	2020	2021	2022	2023	2024 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$(11)	$(33)	$(6)	$(8)	$14	$—	$(44)
Prices provided by external sources (Level 2)	45	(33)	5	—	—	—	17
Prices based on model or other valuation methods (Level 3)[(c)]	291	174	—	(63)	(23)	(53)	326
Total	$325	$108	$(1)	$(71)	$(9)	$(53)	$299

(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 $357 million at December 31, 2018.

(c) Includes ComEd’s net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2019	2020	2021	2022	2023	2024 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts[(a)(b)]:							
Actively quoted prices (Level 1)	$(11)	$(33)	$(6)	$(8)	$14	$—	$(44)
Prices provided by external sources (Level 2)	45	(33)	5	—	—	—	17
Prices based on model or other valuation methods (Level 3)[(c)]	317	199	25	(37)	3	68	575
Total	$351	$133	$24	$(45)	$17	$68	$548

(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 $357 million at December 31, 2018.

166

Table of Contents

ComEd

	Maturities Within						
	2019	2020	2021	2022	2023	2024 and Beyond	Fair Value
Prices based on model or other valuation methods (Level 3)[a]	$(26)	$(25)	$(25)	$(26)	$(26)	$(121)	$(249)

(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 execute derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 12—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 purchases and normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2018. 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 and 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 $43 million, $30 million, $24 million, $28 million, $7 million and $5 million respectively. See Note 25 — Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

Rating as of December 31, 2018	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	$ 795	$ —	$ 795	1	$ 153
Non-investment grade	133	45	88	—	—
No external ratings					
Internally rated—investment grade	181	1	180	—	—
Internally rated—non-investment grade	92	6	86	—	—
Total	$ 1,201	$ 52	$ 1,149	1	$ 153

167

Table of Contents

Rating as of December 31, 2018	Maturity of Credit Risk Exposure Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$755	$ 23	$ 17	$ 795
Non-investment grade	131	2	—	133
No external ratings				
Internally rated—investment grade	126	26	29	181
Internally rated—non-investment grade	82	5	5	92
Total	$1,094	$ 56	$ 51	$ 1,201

Net Credit Exposure by Type of Counterparty	As of December 31, 2018
Financial institutions	$ 12
Investor-owned utilities, marketers, power producers	737
Energy cooperatives and municipalities	324
Other	76
Total	$ 1,149

____

(a) As of December 31, 2018, credit collateral held from counterparties where Generation had credit exposure included $17 million of cash and $35 million of letters of credit.

The Utility Registrants

Credit risk for the Utility Registrants is governed by credit and collection policies, which are aligned with state regulatory requirements. The Utility Registrants are currently obligated to provide service to all electric customers within their franchised territories. The Utility Registrants record a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. The Utility Registrants 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 the allowance for uncollectible accounts policy. The Utility Registrants did not have any customers representing over 10% of their revenues as of December 31, 2018. See Note 4 — Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2018, ComEd, PECO, BGE, Pepco, DPL and ACE's net credit exposure to suppliers was immaterial. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

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. 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. See Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information regarding collateral requirements. See Note 22 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding the letters of credit supporting the cash collateral.

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

168

payments from counterparties could have a material impact on Exelon's and Generation's financial statements. 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. 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.

The Utility Registrants

As of December 31, 2018, ComEd held $38 million in collateral from suppliers in association with energy procurement contracts, approximately $31 million in collateral from suppliers for REC contract obligations and approximately $19 million in collateral from suppliers for long-term renewable energy contracts. BGE is not required to post collateral under its electric supply contracts but was holding an immaterial amount of collateral under its electric supply procurement contracts. BGE was not required to post collateral under its natural gas procurement contracts, but was holding an immaterial amount of collateral under its natural gas procurement contracts. Pepco and DPL were not required to post collateral under their energy and/or natural gas procurement contracts, but were holding an immaterial amount of collateral under their respective electric supply procurement contracts. PECO and ACE were not required to post collateral under their energy and/or natural gas procurement contracts. See Note 4 — Regulatory Matters and Note 12 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

RTOs and ISOs (All Registrants)

All Registrants participate in all, or some, of the established, wholesale spot energy markets that are administered by PJM, ISO-NE, ISO-NY, CAISO, MISO, SPP, AESO, OIESO and ERCOT. 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. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot energy markets that are administered by the RTOs or ISOs, as applicable. In areas where there is no spot energy 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 energy 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' financial statements.

Exchange Traded Transactions (Exelon, Generation, PHI and DPL)

Generation enters into commodity transactions on NYMEX, ICE, NASDAQ, NGX and the Nodal exchange ("the Exchanges"). DPL enters into commodity transactions on ICE. The Exchange clearinghouses act as the counterparty to each trade. Transactions on the Exchanges must adhere to comprehensive collateral and margining requirements. As a result, transactions on Exchanges 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 interest rate swaps to manage their interest rate exposure. At December 31, 2018, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $622 million of notional amounts of floating-to-fixed hedges outstanding. A hypothetical 50 basis point increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a $6 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2018. 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. See Note 12—Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Equity Price Risk (Exelon and Generation)

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning its nuclear plants. As of December 31, 2018, Generation’s NDT funds are reflected at fair value in 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 $529 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 additional information of equity price risk as a result of the current capital and credit market conditions.

Table of Contents

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. 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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of Generation’s results of operations for 2018 compared to 2017 and 2017 compared to 2016 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 credit facilities in the aggregate of $5.3 billion that currently support its commercial paper program and issuances of letters of credit.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund Generation’s capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. Generation spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment.

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.

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.

Table of Contents

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.

Table of Contents

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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of ComEd's results of operations for 2018 compared to 2017 and for 2017 compared to 2016 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, 2018, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund ComEd's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. ComEd spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. 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.

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.

Table of Contents

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.

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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of PECO's results of operations for 2018 compared to 2017 and for 2017 compared to 2016 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, 2018, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund PECO's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. PECO spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. 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.

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.

Table of Contents

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.

Table of Contents

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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of BGE's results of operations for 2018 compared to 2017 and for 2017 compared to 2016 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, 2018, BGE had access to a revolving credit facility with aggregate bank commitments of $600 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund BGE's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. BGE spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. 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.

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.

Table of Contents

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.

Table of Contents

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 Year Ended December 31, 2018 Compared to Year Ended December 31, 2017, Successor Period of March 24, 2016 to December 31, 2016 and Predecessor Period of January 1, 2016 to March 23, 2016

A discussion of PHI's results of operations for 2018 compared to 2017, March 24, 2016 to December 31, 2016 and January 1, 2016 to March 23, 2016 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 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund PHI's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. PHI spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment.

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.

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.

Table of Contents

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.

Table of Contents

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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of Pepco's results of operations for 2018 compared to 2017 and for 2017 compared to 2016 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, 2018, Pepco had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund Pepco's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. Pepco spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. 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.

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.

Table of Contents

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.

Table of Contents

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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of DPL's results of operations for 2018 compared to 2017 and for 2017 compared to 2016 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, 2018, DPL had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund DPL's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. DPL spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. 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.

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.

Table of Contents

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.

Table of Contents

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, 2018 Compared to Year Ended December 31, 2017 and Year Ended December 31, 2017 Compared to Year Ended December 31, 2016

A discussion of ACE's results of operations for 2018 compared to 2017 and for 2017 compared to 2016 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, 2018, ACE had access to a revolving credit facility with aggregate bank commitments of $300 million.

See EXELON CORPORATION — Liquidity and Capital Resources and Note 13 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements of this Form 10-K for additional information.

Capital resources are used primarily to fund ACE's capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. ACE spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. 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.

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.

Table of Contents

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.

Table of Contents

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, 2018. 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, 2018, Exelon's internal control over financial reporting was effective.

The effectiveness of Exelon's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, Generation's internal control over financial reporting was effective.

The effectiveness of Generation's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, ComEd's internal control over financial reporting was effective.

The effectiveness of ComEd's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, PECO's internal control over financial reporting was effective.

The effectiveness of PECO's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, BGE's internal control over financial reporting was effective.

The effectiveness of BGE's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, PHI's internal control over financial reporting was effective.

The effectiveness of PHI's internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, Pepco’s internal control over financial reporting was effective.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, DPL's internal control over financial reporting was effective.

February 8, 2019

Table of Contents

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, 2018. 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, 2018, ACE’s internal control over financial reporting was effective.

February 8, 2019

Table of Contents

Report of Independent Registered Public Accounting Firm
To the Board of Directors and Shareholders of Exelon Corporation

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(1)(i), and the financial statement schedules listed in the index appearing under Item 15(a)(1)(ii), of Exelon Corporation and its subsidiaries (the "Company") (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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

Table of Contents

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 8, 2019

We have served as the Company's auditor since 2000.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Exelon Generation Company, LLC

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(2)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(2)(ii), of Exelon Generation Company, LLC and its subsidiaries (the "Company") (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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

Table of Contents

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 8, 2019

We have served as the Company's auditor since 2001.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Commonwealth Edison Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(3)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(3)(ii), of Commonwealth Edison Company and its subsidiaries (the "Company") (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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

Table of Contents

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 8, 2019

We have served as the Company's auditor since 2000.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of PECO Energy Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(4)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(4)(ii), of PECO Energy Company and its subsidiaries (the "Company") (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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

Table of Contents

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 8, 2019

We have served as the Company's auditor since 1932.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Baltimore Gas and Electric Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(5)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(5)(ii), of Baltimore Gas and Electric Company and its subsidiaries (the "Company") (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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

Table of Contents

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 8, 2019

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Member of Pepco Holdings LLC

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(6)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(6)(iii), of Pepco Holdings LLC and its subsidiaries (Successor) (the "Company") (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2018 and for the period from March 24, 2016 to December 31, 2016 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, 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 the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. 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.

Definition and Limitations of Internal Control over Financial Reporting

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

Table of Contents

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, DC
February 8, 2019

We have served as the Company's auditor since 2001.

207

Table of Contents

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)(6)(ii) present fairly, in all material respects, the results of operations and cash flows of Pepco Holdings LLC and its subsidiaries (formerly Pepco Holdings, Inc.) (Predecessor) for the period January 1, 2016 to March 23, 2016 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule for the period January 1, 2016 to March 23, 2016 listed in the index appearing under Item 15(a)(6)(iv) presents 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 audit. We conducted our audit 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 audit provides a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, DC
February 13, 2017

208

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Potomac Electric Power Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(7)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(7)(ii), of Potomac Electric Power Company (the "Company") (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, DC
February 8, 2019

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Delmarva Power & Light Company

Opinion on the Financial Statements

We have audited the financial statements, including the related notes, as listed in the index appearing under Item 15(a)(8)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(8)(ii), of Delmarva Power & Light Company (the "Company") (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, DC
February 8, 2019

We have served as the Company's auditor since at least 1993. We have not been able to determine the specific year we began serving as auditor of the Company.

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholder of Atlantic City Electric Company

Opinion on the Financial Statements

We have audited the consolidated financial statements, including the related notes, as listed in the index appearing under Item 15(a)(9)(i), and the financial statement schedule listed in the index appearing under Item 15(a)(9)(ii), of Atlantic City Electric Company and its subsidiary (the "Company") (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP
Washington, DC
February 8, 2019

We have served as the Company's auditor since 1998.

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions, except per share data)	2018	2017	2016
Operating revenues			
Competitive businesses revenues	$19,168	$17,394	$16,330
Rate-regulated utility revenues	16,879	15,964	14,988
Revenues from alternative revenue programs	(62)	207	48
Total operating revenues	35,985	33,565	31,366
Operating expenses			
Competitive businesses purchased power and fuel	11,679	9,668	8,817
Rate-regulated utility purchased power and fuel	4,991	4,367	3,823
Operating and maintenance	9,337	10,025	9,954
Depreciation and amortization	4,353	3,828	3,936
Taxes other than income	1,783	1,731	1,576
Total operating expenses	32,143	29,619	28,106
Gain (loss) on sales of assets and businesses	56	3	(48)
Bargain purchase gain	—	233	—
Gain on deconsolidation of business	—	213	—
Operating income	3,898	4,395	3,212
Other income and (deductions)			
Interest expense, net	(1,529)	(1,524)	(1,495)
Interest expense to affiliates	(25)	(36)	(41)
Other, net	(112)	947	297
Total other income and (deductions)	(1,666)	(613)	(1,239)
Income before income taxes	2,232	3,782	1,973
Income taxes	120	(126)	753
Equity in losses of unconsolidated affiliates	(28)	(32)	(24)
Net income	2,084	3,876	1,196
Net income attributable to noncontrolling interests and preference stock dividends	74	90	75
Net income attributable to common shareholders	$2,010	$3,786	$1,121
Comprehensive income, net of income taxes			
Net income	$2,084	$3,876	$1,196
Other comprehensive income (loss), net of income taxes			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	(66)	(56)	(48)
Actuarial loss reclassified to periodic benefit cost	247	197	184
Pension and non-pension postretirement benefit plan valuation adjustment	(143)	10	(181)
Unrealized gain on cash flow hedges	12	3	2
Unrealized gain on marketable securities	—	6	1
Unrealized gain (loss) on investments in unconsolidated affiliates	2	4	(4)
Unrealized (loss) gain on foreign currency translation	(10)	7	10
Other comprehensive income (loss)	42	171	(36)
Comprehensive income	2,126	4,047	1,160
Comprehensive income attributable to noncontrolling interests and preference stock dividends	75	88	75
Comprehensive income attributable to common shareholders	$2,051	$3,959	$1,085

Average shares of common stock outstanding:			
Basic	967	947	924
Diluted	969	949	927
Earnings per average common share:			
Basic	$2.08	$4.00	$1.21
Diluted	$2.07	$3.99	$1.21

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2018	2017	2016
Cash flows from operating activities			
Net income	$2,084	$3,876	$1,196
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	5,971	5,427	5,576
Impairment losses of long-lived assets, intangibles and regulatory assets	50	573	306
Gain on deconsolidation of business	—	(213)	—
(Gain) loss on sales of assets and businesses	(56)	(3)	48
Bargain purchase gain	—	(233)	—
Deferred income taxes and amortization of investment tax credits	(106)	(362)	656
Net fair value changes related to derivatives	294	151	24
Net realized and unrealized losses (gains) on NDT funds	303	(616)	(229)
Other non-cash operating activities	1,124	721	1,333
Changes in assets and liabilities:			
Accounts receivable	(565)	(470)	(432)
Inventories	(37)	(72)	7
Accounts payable and accrued expenses	551	(388)	771
Option premiums (paid) received, net	(43)	28	(66)
Collateral received (posted), net	82	(158)	931
Income taxes	340	299	576
Pension and non-pension postretirement benefit contributions	(383)	(405)	(397)
Deposit with IRS	—	—	(1,250)
Other assets and liabilities	(965)	(675)	(589)
Net cash flows provided by operating activities	8,644	7,480	8,461
Cash flows from investing activities			
Capital expenditures	(7,594)	(7,584)	(8,553)
Proceeds from termination of direct financing lease investment	—	—	360
Proceeds from NDT fund sales	8,762	7,845	9,496
Investment in NDT funds	(8,997)	(8,113)	(9,738)
Reduction of restricted cash from deconsolidation of business	—	(87)	—
Acquisitions of assets and businesses, net	(154)	(208)	(6,923)
Proceeds from sales of assets and businesses	91	219	61
Other investing activities	58	(43)	(153)
Net cash flows used in investing activities	(7,834)	(7,971)	(15,450)
Cash flows from financing activities			
Changes in short-term borrowings	(338)	(261)	(353)
Proceeds from short-term borrowings with maturities greater than 90 days	126	621	240
Repayments on short-term borrowings with maturities greater than 90 days	(1)	(700)	(462)
Issuance of long-term debt	3,115	3,470	4,716
Retirement of long-term debt	(1,786)	(2,490)	(1,936)
Retirement of long-term debt to financing trust	—	(250)	—
Common stock issued from treasury stock	—	1,150	—
Redemption of preference stock	—	—	(190)

Dividends paid on common stock	(1,332)	(1,236)	(1,166)
Proceeds from employee stock plans	105	150	55
Sale of noncontrolling interests	—	396	372
Other financing activities	(108)	(83)	(85)
Net cash flows (used in) provided by financing activities	(219)	767	1,191
Increase (decrease) in cash, cash equivalents and restricted cash	591	276	(5,798)
Cash, cash equivalents and restricted cash at beginning of period	1,190	914	6,712
Cash, cash equivalents and restricted cash at end of period	$1,781	$1,190	$914

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$1,349	$898
Restricted cash and cash equivalents	247	207
Accounts receivable, net		
Customer	4,607	4,445
Other	1,256	1,132
Mark-to-market derivative assets	804	976
Unamortized energy contract assets	48	60
Inventories, net		
Fossil fuel and emission allowances	334	340
Materials and supplies	1,351	1,311
Regulatory assets	1,222	1,267
Assets held for sale	904	—
Other	1,238	1,260
Total current assets	13,360	11,896
Property, plant and equipment, net	76,707	74,202
Deferred debits and other assets		
Regulatory assets	8,237	8,021
Nuclear decommissioning trust funds	11,661	13,272
Investments	625	640
Goodwill	6,677	6,677
Mark-to-market derivative assets	452	337
Unamortized energy contract assets	372	395
Other	1,575	1,330
Total deferred debits and other assets	29,599	30,672
Total assets[a]	$119,666	$116,770

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2018	2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$714	$929
Long-term debt due within one year	1,349	2,088
Accounts payable	3,800	3,532
Accrued expenses	2,112	1,837
Payables to affiliates	5	5
Regulatory liabilities	644	523
Mark-to-market derivative liabilities	475	232
Unamortized energy contract liabilities	149	231
Renewable energy credit obligation	344	352
Liabilities held for sale	777	—
Other	1,035	1,069
Total current liabilities	11,404	10,798
Long-term debt	34,075	32,176
Long-term debt to financing trusts	390	389
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,330	11,235
Asset retirement obligations	9,679	10,029
Pension obligations	3,988	3,736
Non-pension postretirement benefit obligations	1,928	2,093
Spent nuclear fuel obligation	1,171	1,147
Regulatory liabilities	9,559	9,865
Mark-to-market derivative liabilities	479	409
Unamortized energy contract liabilities	463	609
Other	2,130	2,097
Total deferred credits and other liabilities	40,727	41,220
Total liabilities[(a)]	86,596	84,583
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 968 shares and 963 shares outstanding at December 31, 2018 and 2017, respectively)	19,116	18,964
Treasury stock, at cost (2 shares at December 31, 2018 and 2017)	(123)	(123)
Retained earnings	14,766	14,081
Accumulated other comprehensive loss, net	(2,995)	(3,026)
Total shareholders' equity	30,764	29,896
Noncontrolling interests	2,306	2,291
Total equity	33,070	32,187
Total liabilities and equity	$119,666	$116,770

(a) Exelon's consolidated assets include $9,667 million and $9,597 million at December 31, 2018 and 2017, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include $3,548 million and $3,618 million at December 31, 2018 and 2017, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 2–Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Changes in Equity

	Shareholders' Equity							
(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interests	Preference Stock	Total Equity
Balance, December 31, 2015	954,668	$18,676	$(2,327)	$12,104	$ (2,624)	$ 1,308	$ 193	$27,330
Net income	—	—	—	1,121	—	67	8	1,196
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
Adjustment of contingently redeemable noncontrolling interest to redemption value	—	—	—	—	—	157	—	157
Common stock dividends ($1.26/common share)	—	—	—	(1,172)	—	—	—	(1,172)
Preferred and preference stock	—	—	—	—	—	—	(8)	(8)
Sale of noncontrolling interests	—	(4)	—	—	—	243	—	239
Redemption of preference stock	—	—	—	—	—	—	(193)	(193)
Other comprehensive loss, net of income taxes	—	—	—	—	(36)	—	—	(36)
Balance, December 31, 2016	958,778	$18,794	$(2,327)	$12,053	$ (2,660)	$ 1,780	$ —	$27,640
Net income	—	—	—	3,786	—	90	—	3,876
Long-term incentive plan activity	5,066	56	—	—	—	—	—	56
Employee stock purchase plan issuances	1,324	150	—	—	—	—	—	150
Common stock issued from treasury stock	—	—	2,204	(1,054)	—	—	—	1,150
Sale of noncontrolling interests	—	(36)	—	—	—	443	—	407
Changes in equity of noncontrolling interests	—	—	—	—	—	(20)	—	(20)
Common stock dividends ($1.31/common share)	—	—	—	(1,243)	—	—	—	(1,243)
Other comprehensive income (loss), net of income taxes	—	—	—	—	173	(2)	—	171
Impact of adoption of Reclassification of Certain Tax Effects from AOCI standard	—	—	—	539	(539)	—	—	—
Balance, December 31, 2017	965,168	$18,964	$(123)	$14,081	$ (3,026)	$ 2,291	$ —	$32,187
Net income	—	—	—	2,010	—	74	—	2,084
Long-term incentive plan activity	3,534	41	—	—	—	—	—	41

Employee stock purchase plan issuances	1,318	105	—	—	—	—	—	105
Changes in equity of noncontrolling interests	—	—	—	—	—	(60)	—	(60)
Sale of noncontrolling interests	—	6	—	—	—	—	—	6
Common stock dividends ($1.38/common share)	—	—	—	(1,339)	—	—	—	(1,339)
Other comprehensive income, net of income taxes	—	—	—	—	41	1	—	42
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	—	—	14	(10)	—	—	4
Balance, December 31, 2018	970,020	$19,116	$(123)	$14,766	$ (2,995)	$ 2,306	$ —	$33,070

See the Combined Notes to Consolidated Financial Statements

216

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Operating revenues			
Operating revenues	$19,169	$17,385	$16,318
Operating revenues from affiliates	1,268	1,115	1,439
Total operating revenues	20,437	18,500	17,757
Operating expenses			
Purchased power and fuel	11,679	9,671	8,818
Purchased power and fuel from affiliates	14	19	12
Operating and maintenance	4,803	5,602	5,000
Operating and maintenance from affiliates	661	697	663
Depreciation and amortization	1,797	1,457	1,879
Taxes other than income	556	555	506
Total operating expenses	19,510	18,001	16,878
Gain (loss) on sales of assets and businesses	48	2	(59)
Bargain purchase gain	—	233	—
Gain on deconsolidation of business	—	213	—
Operating income	975	947	820
Other income and (deductions)			
Interest expense, net	(396)	(401)	(325)
Interest expense to affiliates	(36)	(39)	(39)
Other, net	(178)	948	401
Total other income and (deductions)	(610)	508	37
Income before income taxes	365	1,455	857
Income taxes	(108)	(1,376)	282
Equity in losses of unconsolidated affiliates	(30)	(33)	(25)
Net income	443	2,798	550
Net income attributable to noncontrolling interests	73	88	67
Net income attributable to membership interest	$370	$2,710	$483
Comprehensive income, net of income taxes			
Net income	$443	$2,798	$550
Other comprehensive income (loss), net of income taxes			
Unrealized gain on cash flow hedges	12	3	2
Unrealized gain (loss) on investments in unconsolidated affiliates	1	4	(4)
Unrealized (loss) gain on foreign currency translation	(10)	7	10
Unrealized gain on marketable securities	—	1	1
Other comprehensive income	3	15	9
Comprehensive income	$446	$2,813	$559
Comprehensive income attributable to noncontrolling interests	74	86	67
Comprehensive income attributable to membership interest	$372	$2,727	$492

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Cash flows from operating activities			
Net income	$443	$2,798	$550
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel and energy contract amortization	3,415	3,056	3,519
Impairment losses of long-lived assets	50	510	243
Gain on deconsolidation of business	—	(213)	—
(Gain) loss on sales of assets and businesses	(48)	(2)	59
Bargain purchase gain	—	(233)	—
Deferred income taxes and amortization of investment tax credits	(451)	(2,023)	(277)
Net fair value changes related to derivatives	307	167	40
Net realized and unrealized losses (gains) on NDT fund investments	303	(616)	(229)
Other non-cash operating activities	298	112	15
Changes in assets and liabilities:			
Accounts receivable	(359)	(320)	(152)
Receivables from and payables to affiliates, net	8	(7)	(21)
Inventories	(12)	(29)	(4)
Accounts payable and accrued expenses	376	4	29
Option premiums (paid) received, net	(43)	28	(66)
Collateral received (posted), net	64	(129)	923
Income taxes	(193)	496	182
Pension and non-pension postretirement benefit contributions	(139)	(148)	(152)
Other assets and liabilities	(158)	(152)	(217)
Net cash flows provided by operating activities	3,861	3,299	4,442
Cash flows from investing activities			
Capital expenditures	(2,242)	(2,259)	(3,078)
Proceeds from NDT fund sales	8,762	7,845	9,496
Investment in NDT funds	(8,997)	(8,113)	(9,738)
Reduction of restricted cash from deconsolidation of business	—	(87)	—
Proceeds from sales of assets and businesses	90	218	37
Acquisitions of assets and businesses, net	(154)	(208)	(293)
Other investing activities	10	(58)	(240)
Net cash flows used in investing activities	(2,531)	(2,662)	(3,816)
Cash flows from financing activities			
Change in short-term borrowings	—	(620)	620
Proceeds from short-term borrowings with maturities greater than 90 days	1	121	240
Repayments of short-term borrowings with maturities greater than 90 days	(1)	(200)	(162)
Issuance of long-term debt	15	1,645	388
Retirement of long-term debt	(141)	(1,261)	(202)
Changes in Exelon intercompany money pool	46	(1)	(1,191)
Distributions to member	(1,001)	(659)	(922)
Contributions from member	155	102	142
Sale of noncontrolling interests	—	396	372

Other financing activities	(55)	(54)	(19)
Net cash flows used in financing activities	(981)	(531)	(734)
Increase (decrease) in cash, cash equivalents and restricted cash	349	106	(108)
Cash, cash equivalents and restricted cash at beginning of period	554	448	556
Cash, cash equivalents and restricted cash at end of period	$903	$554	$448

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$750	$416
Restricted cash and cash equivalents	153	138
Accounts receivable, net		
Customer	2,941	2,697
Other	562	321
Mark-to-market derivative assets	804	976
Receivables from affiliates	173	140
Unamortized energy contract assets	49	60
Inventories, net		
Fossil fuel and emission allowances	251	264
Materials and supplies	963	937
Assets held for sale	904	—
Other	883	933
Total current assets	8,433	6,882
Property, plant and equipment, net	23,981	24,906
Deferred debits and other assets		
Nuclear decommissioning trust funds	11,661	13,272
Investments	414	433
Goodwill	47	47
Mark-to-market derivative assets	452	334
Prepaid pension asset	1,421	1,502
Unamortized energy contract assets	371	395
Deferred income taxes	21	16
Other	755	670
Total deferred debits and other assets	15,142	16,669
Total assets[(a)]	$47,556	$48,457

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$—	$2
Long-term debt due within one year	906	346
Accounts payable	1,847	1,773
Accrued expenses	898	1,022
Payables to affiliates	139	123
Borrowings from Exelon intercompany money pool	100	54
Mark-to-market derivative liabilities	449	211
Unamortized energy contract liabilities	31	43
Renewable energy credit obligation	343	352
Liabilities held for sale	777	—
Other	279	265
Total current liabilities	5,769	4,191
Long-term debt	6,989	7,734
Long-term debt to affiliates	898	910
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,383	3,811
Asset retirement obligations	9,450	9,844
Non-pension postretirement benefit obligations	900	916
Spent nuclear fuel obligation	1,171	1,147
Payables to affiliates	2,606	3,065
Mark-to-market derivative liabilities	252	174
Unamortized energy contract liabilities	20	48
Other	610	658
Total deferred credits and other liabilities	18,392	19,663
Total liabilities[(a)]	32,048	32,498
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,518	9,357
Undistributed earnings	3,724	4,349
Accumulated other comprehensive loss, net	(38)	(37)
Total member's equity	13,204	13,669
Noncontrolling interests	2,304	2,290
Total equity	15,508	15,959
Total liabilities and equity	$47,556	$48,457

(a) Generation's consolidated assets include $9,634 million and $9,556 million at December 31, 2018 and 2017, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include $3,480 million and $3,516 million at December 31, 2018 and 2017, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 2–Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions)	Member's Equity: Membership Interest	Member's Equity: Undistributed Earnings	Member's Equity: Accumulated Other Comprehensive Loss, net	Noncontrolling Interests	Total Equity
Balance, December 31, 2015	$8,997	$ 2,737	$ (63)	$ 1,307	$12,978
Net income	—	483	—	67	550
Sale of noncontrolling interests	(4)	—	—	243	239
Adjustment of contingently redeemable noncontrolling interests due to release of contingency	—	—	—	157	157
Changes in equity of noncontrolling interests	—	—	—	5	5
Contributions from member	268	—	—	—	268
Distributions to member	—	(922)	—	—	(922)
Other comprehensive income, net of income taxes	—	—	9	—	9
Balance, December 31, 2016	$9,261	$ 2,298	$ (54)	$ 1,779	$13,284
Net income	—	2,710	—	88	2,798
Sale of noncontrolling interests	(36)	—	—	443	407
Changes in equity of noncontrolling interests	—	—	—	(18)	(18)
Distribution of net retirement benefit obligation to member	33	—	—	—	33
Contributions from member	99	—	—	—	99
Distributions to member	—	(659)	—	—	(659)
Other comprehensive income (loss), net of income taxes	—	—	17	(2)	15
Balance, December 31, 2017	$9,357	$ 4,349	$ (37)	$ 2,290	$15,959
Net income	—	370	—	73	443
Sale of noncontrolling interests	6	—	—	—	6
Changes in equity of noncontrolling interests	—	—	—	(60)	(60)
Contributions from member	155	—	—	—	155
Distributions to member	—	(1,001)	—	—	(1,001)
Other comprehensive income, net of income taxes	—	—	2	1	3
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	6	(3)	—	3
Balance, December 31, 2018	$9,518	$ 3,724	$ (38)	$ 2,304	$15,508

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2018	2017	2016
Operating revenues			
Electric operating revenues	$5,884	$5,478	$5,263
Revenues from alternative revenue programs	(29)	43	(24)
Operating revenues from affiliates	27	15	15
Total operating revenues	5,882	5,536	5,254
Operating expenses			
Purchased power	1,626	1,533	1,411
Purchased power from affiliates	529	108	47
Operating and maintenance	1,068	1,157	1,303
Operating and maintenance from affiliates	267	270	227
Depreciation and amortization	940	850	775
Taxes other than income	311	296	293
Total operating expenses	4,741	4,214	4,056
Gain on sales of assets	5	1	7
Operating income	1,146	1,323	1,205
Other income and (deductions)			
Interest expense, net	(334)	(348)	(448)
Interest expense to affiliates	(13)	(13)	(13)
Other, net	33	22	(65)
Total other income and (deductions)	(314)	(339)	(526)
Income before income taxes	832	984	679
Income taxes	168	417	301
Net income	$664	$567	$378
Comprehensive income	$664	$567	$378

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2018	2017	2016
Cash flows from operating activities			
Net income	$ 664	$ 567	$ 378
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	940	850	775
Deferred income taxes and amortization of investment tax credits	259	659	439
Other non-cash operating activities	242	164	215
Changes in assets and liabilities:			
Accounts receivable	(136)	(59)	(25)
Receivables from and payables to affiliates, net	26	8	3
Inventories	1	4	1
Accounts payable and accrued expenses	70	(297)	339
Counterparty collateral received (posted), net and cash deposits	11	(26)	7
Income taxes	62	(308)	306
Pension and non-pension postretirement benefit contributions	(42)	(41)	(38)
Other assets and liabilities	(348)	6	105
Net cash flows provided by operating activities	1,749	1,527	2,505
Cash flows from investing activities			
Capital expenditures	(2,126)	(2,250)	(2,734)

Other investing activities	29	20	49
Net cash flows used in investing activities	(2,097)	(2,230)	(2,685)
Cash flows from financing activities			
Changes in short-term borrowings	—	—	(294)
Issuance of long-term debt	1,350	1,000	1,200
Retirement of long-term debt	(840)	(425)	(665)
Contributions from parent	500	651	315
Dividends paid on common stock	(459)	(422)	(369)
Other financing activities	(17)	(15)	(18)
Net cash flows provided by financing activities	534	789	169
Increase (decrease) in cash, cash equivalents and restricted cash	186	86	(11)
Cash, cash equivalents and restricted cash at beginning of period	144	58	69
Cash, cash equivalents and restricted cash at end of period	$ 330	$ 144	$ 58

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$135	$76
Restricted cash and cash equivalents	29	5
Accounts receivable, net		
Customer	539	559
Other	320	266
Receivables from affiliates	20	13
Inventories, net	148	152
Regulatory assets	293	225
Other	86	68
Total current assets	1,570	1,364
Property, plant and equipment, net	22,058	20,723
Deferred debits and other assets		
Regulatory assets	1,307	1,054
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,217	2,528
Prepaid pension asset	1,035	1,188
Other	395	238
Total deferred debits and other assets	7,585	7,639
Total assets	$31,213	$29,726

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2018	2017
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long-term debt due within one year	$300	$840
Accounts payable	607	568
Accrued expenses	373	327
Payables to affiliates	119	74
Customer deposits	111	112
Regulatory liabilities	293	249
Mark-to-market derivative liability	26	21
Other	96	103
Total current liabilities	1,925	2,294
Long-term debt	7,801	6,761
Long-term debt to financing trust	205	205
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,813	3,469
Asset retirement obligations	118	111
Non-pension postretirement benefits obligations	201	219
Regulatory liabilities	6,050	6,328
Mark-to-market derivative liability	223	235
Other	630	562
Total deferred credits and other liabilities	11,035	10,924
Total liabilities	20,966	20,184
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	7,322	6,822
Retained deficit unappropriated	(1,639)	(1,639)
Retained earnings appropriated	2,976	2,771
Total shareholders' equity	10,247	9,542
Total liabilities and shareholders' equity	$31,213	$29,726

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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, 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
Net income	—	—	567	—	567
Common stock dividends	—	—	—	(422)	(422)
Contributions from parent	—	651	—	—	651
Parent tax matter indemnification	—	21	—	—	21
Appropriation of retained earnings for future dividends	—	—	(567)	567	—
Balance, December 31, 2017	$ 1,588	$ 6,822	$ (1,639)	$ 2,771	$ 9,542
Net income	—	—	664	—	664
Common stock dividends	—	—	—	(459)	(459)
Contributions from parent	—	500	—	—	500
Appropriation of retained earnings for future dividends	—	—	(664)	664	—
Balance, December 31, 2018	$ 1,588	$ 7,322	$ (1,639)	$ 2,976	$ 10,247

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Operating revenues			
Electric operating revenues	$2,469	$2,369	$2,524
Natural gas operating revenues	568	494	462
Revenues from alternative revenue programs	(7)	—	—
Operating revenues from affiliates	8	7	8
Total operating revenues	3,038	2,870	2,994
Operating expenses			
Purchased power	734	648	598
Purchased fuel	230	186	162
Purchased power from affiliates	126	135	287
Operating and maintenance	742	657	665
Operating and maintenance from affiliates	156	149	146
Depreciation and amortization	301	286	270
Taxes other than income	163	154	164
Total operating expenses	2,452	2,215	2,292
Gain on sales of assets	1	—	—
Operating income	587	655	702
Other income and (deductions)			
Interest expense, net	(115)	(115)	(111)
Interest expense to affiliates, net	(14)	(11)	(12)
Other, net	8	9	8
Total other income and (deductions)	(121)	(117)	(115)
Income before income taxes	466	538	587
Income taxes	6	104	149
Net income	$460	$434	$438
Comprehensive income	$460	$434	$438

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2018	2017	2016
Cash flows from operating activities			
Net income	$460	$434	$438
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	301	286	270
Deferred income taxes and amortization of investment tax credits	(5)	19	78
Other non-cash operating activities	51	54	65
Changes in assets and liabilities:			
Accounts receivable	(74)	(44)	(71)
Receivables from and payables to affiliates, net	7	(6)	6
Inventories	(14)	1	6
Accounts payable and accrued expenses	(3)	6	67
Income taxes	15	34	8
Pension and non-pension postretirement benefit contributions	(28)	(24)	(30)
Other assets and liabilities	29	(5)	(8)
Net cash flows provided by operating activities	739	755	829
Cash flows from investing activities			
Capital expenditures	(849)	(732)	(686)
Changes in intercompany money pool	—	131	(131)
Other investing activities	9	4	20
Net cash flows used in investing activities	(840)	(597)	(797)
Cash flows from financing activities			
Issuance of long-term debt	700	325	300
Retirement of long-term debt	(500)	—	(300)
Contributions from parent	89	16	18
Dividends paid on common stock	(306)	(288)	(277)
Other financing activities	(22)	(3)	(4)
Net cash flows (used in) provided by financing activities	(39)	50	(263)
(Decrease) increase in cash, cash equivalents and restricted cash	(140)	208	(231)
Cash, cash equivalents and restricted cash at beginning of period	275	67	298
Cash, cash equivalents and restricted cash at end of period	$135	$275	$67

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$130	$271
Restricted cash and cash equivalents	5	4
Accounts receivable, net		
Customer	321	327
Other	151	105
Inventories, net		
Fossil fuel	38	31
Materials and supplies	37	30
Prepaid utility taxes	—	8
Regulatory assets	81	29
Other	19	17
Total current assets	782	822
Property, plant and equipment, net	8,610	8,053
Deferred debits and other assets		
Regulatory assets	460	381
Investments	25	25
Receivables from affiliates	389	537
Prepaid pension asset	349	340
Other	27	12
Total deferred debits and other assets	1,250	1,295
Total assets	$10,642	$10,170

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Long-term debt due within one year	$—	$500
Accounts payable	370	370
Accrued expenses	113	114
Payables to affiliates	59	53
Customer deposits	68	66
Regulatory liabilities	175	141
Other	24	23
Total current liabilities	809	1,267
Long-term debt	3,084	2,403
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,933	1,789
Asset retirement obligations	27	27
Non-pension postretirement benefits obligations	288	288
Regulatory liabilities	421	549
Other	76	86
Total deferred credits and other liabilities	2,745	2,739
Total liabilities	6,822	6,593
Commitments and contingencies		
Shareholder's equity		
Common stock	2,578	2,489
Retained earnings	1,242	1,087
Accumulated other comprehensive income, net	—	1
Total shareholder's equity	3,820	3,577
Total liabilities and shareholder's equity	$10,642	$10,170

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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, 2015	$ 2,455	$ 780	$ 1	$ 3,236
Net income	—	438	—	438
Common stock dividends	—	(277)	—	(277)
Contributions from parent	18	—	—	18
Balance, December 31, 2016	$ 2,473	$ 941	$ 1	$ 3,415
Net income	—	434	—	434
Common stock dividends	—	(288)	—	(288)
Contributions from parent	16	—	—	16
Balance, December 31, 2017	$ 2,489	$ 1,087	$ 1	$ 3,577
Net income	—	460	—	460
Common stock dividends	—	(306)	—	(306)
Contributions from parent	89	—	—	89
Impact of adoption of Recognition and Measurement of Financial Assets and Liabilities standard	—	1	(1)	—
Balance, December 31, 2018	$ 2,578	$ 1,242	$ —	$ 3,820

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2018	2017	2016
Operating revenues			
Electric operating revenues	$2,428	$2,384	$2,531
Natural gas operating revenues	738	652	628
Revenues from alternative revenue programs	(26)	124	53
Operating revenues from affiliates	29	16	21
Total operating revenues	3,169	3,176	3,233
Operating expenses			
Purchased power	671	566	528
Purchased fuel	254	183	162
Purchased power from affiliates	257	384	604
Operating and maintenance	615	563	605
Operating and maintenance from affiliates	162	153	132
Depreciation and amortization	483	473	423
Taxes other than income	254	240	229
Total operating expenses	2,696	2,562	2,683
Gain on sales of assets	1	—	—
Operating income	474	614	550
Other income and (deductions)			
Interest expense, net	(106)	(95)	(87)
Interest expense to affiliates	—	(10)	(16)
Other, net	19	16	21
Total other income and (deductions)	(87)	(89)	(82)
Income before income taxes	387	525	468
Income taxes	74	218	174
Net income	313	307	294
Preference stock dividends	—	—	8
Net income attributable to common shareholder	$313	$307	$286
Comprehensive income	$313	$307	$294
Comprehensive income attributable to preference stock dividends	—	—	8
Comprehensive income attributable to common shareholder	$313	$307	$286

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Cash flows from operating activities			
Net income	$ 313	$ 307	$ 294
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	483	473	423
Impairment losses on long-lived assets and regulatory assets	—	7	52
Deferred income taxes and amortization of investment tax credits	76	145	118
Other non-cash operating activities	58	65	88
Changes in assets and liabilities:			
Accounts receivable	8	(5)	(98)
Receivables from and payables to affiliates, net	12	(4)	3
Inventories	2	(9)	1
Accounts payable and accrued expenses	(1)	(15)	138
Collateral received, net	4	—	—
Income taxes	(20)	60	18
Pension and non-pension postretirement benefit contributions	(54)	(53)	(49)
Other assets and liabilities	(92)	(150)	(43)
Net cash flows provided by operating activities	789	821	945
Cash flows from investing activities			
Capital expenditures	(959)	(882)	(934)

Other investing activities	9	7	24
Net cash flows used in investing activities	(950)	(875)	(910)
Cash flows from financing activities			
Changes in short-term borrowings	(42)	32	(165)
Issuance of long-term debt	300	300	850
Retirement of long-term debt	—	(41)	(379)
Retirement of long-term debt to financing trust	—	(250)	—
Redemption of preference stock	—	—	(190)
Dividends paid on preference stock	—	—	(8)
Dividends paid on common stock	(209)	(198)	(179)
Contributions from parent	109	184	61
Other financing activities	(2)	(5)	(11)
Net cash flows provided by (used in) financing activities	156	22	(21)
(Decrease) increase in cash, cash equivalents and restricted cash	(5)	(32)	14
Cash, cash equivalents and restricted cash at beginning of period	18	50	36
Cash, cash equivalents and restricted cash at end of period	$ 13	$ 18	$ 50

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$7	$17
Restricted cash and cash equivalents	6	1
Accounts receivable, net		
Customer	353	375
Other	90	94
Receivables from affiliates	1	1
Inventories, net		
Gas held in storage	36	37
Materials and supplies	39	40
Prepaid utility taxes	74	69
Regulatory assets	177	174
Other	3	3
Total current assets	786	811
Property, plant and equipment, net	8,243	7,602
Deferred debits and other assets		
Regulatory assets	398	397
Investments	5	5
Prepaid pension asset	279	285
Other	5	4
Total deferred debits and other assets	687	691
Total assets	$9,716	$9,104

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$35	$77
Accounts payable	295	265
Accrued expenses	155	164
Payables to affiliates	65	52
Customer deposits	120	116
Regulatory liabilities	77	62
Other	27	24
Total current liabilities	774	760
Long-term debt	2,876	2,577
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,222	1,244
Asset retirement obligations	24	23
Non-pension postretirement benefits obligations	201	202
Regulatory liabilities	1,192	1,101
Other	73	56
Total deferred credits and other liabilities	2,712	2,626
Total liabilities	6,362	5,963
Commitments and contingencies		
Shareholder's equity		
Common stock	1,714	1,605
Retained earnings	1,640	1,536
Total shareholder's equity	3,354	3,141
Total liabilities and shareholder's equity	$9,716	$9,104

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Baltimore Gas and Electric Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity	Preference stock not subject to mandatory redemption	Total Equity
Balance, December 31, 2015	$ 1,367	$ 1,320	$ 2,687	$ 190	$ 2,877
Net income	—	294	294	—	294
Preference stock dividends	—	(8)	(8)	—	(8)
Common stock dividends	—	(179)	(179)	—	(179)
Distributions to parent	(7)	—	(7)		(7)
Contributions from parent	61	—	61	—	61
Redemption of preference stock	—	—	—	(190)	(190)
Balance, December 31, 2016	$ 1,421	$ 1,427	$ 2,848	$ —	$ 2,848
Net income	—	307	307	—	307
Common stock dividends	—	(198)	(198)	—	(198)
Contributions from parent	184	—	184	—	184
Balance, December 31, 2017	$ 1,605	$ 1,536	$ 3,141	$ —	$ 3,141
Net income	—	313	313	—	313
Common stock dividends	—	(209)	(209)	—	(209)
Contributions from parent	109	—	109	—	109
Balance, December 31, 2018	$ 1,714	$ 1,640	$ 3,354	$ —	$ 3,354

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income (Loss)

	Successor			Predecessor
	For the Years Ended December 31,		March 24 to December 31,	January 1 to March 23,
(In millions)	2018	2017	2016	2016
Operating revenues				
Electric operating revenues	$4,609	$4,428	$ 3,463	$ 1,122
Natural gas operating revenues	181	161	92	57
Revenues from alternative revenue programs	—	40	43	(26)
Operating revenues from affiliates	15	50	45	—
Total operating revenues	4,805	4,679	3,643	1,153
Operating expenses				
Purchased power	1,387	1,182	925	471
Purchased fuel	89	71	36	26
Purchased power from affiliates	355	463	486	—
Operating and maintenance	978	918	1,144	294
Operating and maintenance from affiliates	152	150	89	—
Depreciation, amortization and accretion	740	675	515	152
Taxes other than income	455	452	354	105
Total operating expenses	4,156	3,911	3,549	1,048
Gain (loss) on sales of assets	1	1	(1)	—
Operating income	650	769	93	105
Other income and (deductions)				
Interest expense, net	(261)	(245)	(195)	(65)
Other, net	43	54	44	(4)
Total other income and (deductions)	(218)	(191)	(151)	(69)
Income (loss) before income taxes	432	578	(58)	36
Income taxes	35	217	3	17
Equity in earnings of unconsolidated affiliates	1	1	—	—
Net income (loss)	398	362	(61)	19
Net income (loss) attributable to membership interest/common shareholders	$398	$362	$ (61)	$ 19
Comprehensive income (loss), net of income taxes				
Net income (loss)	$398	$362	$ (61)	$ 19
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Actuarial loss reclassified to periodic cost	—	—	—	1
Other comprehensive income	—	—	—	1
Comprehensive income (loss)	$398	$362	$ (61)	$ 20

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

	Successor			Predecessor
	For the Years Ended December 31,		March 24 to December 31,	January 1 to March 23,
(In millions)	2018	2017	2016	2016
Cash flows from operating activities				
Net income (loss)	$398	$362	$ (61)	$ 19
Adjustments to reconcile net income (loss) to net cash from operating activities:				
Depreciation and amortization	740	675	515	152
Impairment losses on intangibles and regulatory assets	—	52	—	—
Deferred income taxes and amortization of investment tax credits	32	252	295	19
Net fair value changes related to derivatives	—	—	—	18
Other non-cash operating activities	143	58	515	46
Changes in assets and liabilities:				
Accounts receivable	(2)	(26)	(21)	(28)
Receivables from and payables to affiliates, net	8	(2)	42	—
Inventories	(14)	(37)	3	(4)
Accounts payable and accrued expenses	45	(106)	19	42
Income taxes	34	79	(22)	12
Pension and non-pension postretirement benefit contributions	(74)	(99)	(86)	(4)
Other assets and liabilities	(178)	(258)	(311)	(8)
Net cash flows provided by operating activities	1,132	950	888	264
Cash flows from investing activities				
Capital expenditures	(1,375)	(1,396)	(1,008)	(273)
Purchases of investments	—	—	—	(68)
Other investing activities	4	(1)	15	(5)
Net cash flows used in investing activities	(1,371)	(1,397)	(993)	(346)
Cash flows from financing activities				
Changes in short-term borrowings	(296)	328	(515)	(121)
Proceeds from short-term borrowings with maturities greater than 90 days	125	—	—	500
Repayments of short-term borrowings with maturities greater than 90 days	—	(500)	(300)	—
Issuance of long-term debt	750	202	179	—
Retirement of long-term debt	(299)	(169)	(338)	(11)
Common stock issued for the Direct Stock Purchase and Dividend Reinvestment Plan and employee-related compensation	—	—	—	2
Distributions to member	(326)	(311)	(273)	—
Contributions from member	385	758	1,251	—
Change in Exelon intercompany money pool	—	—	(6)	—
Other financing activities	(9)	(2)	(5)	2
Net cash flows provided by (used in) financing activities	330	306	(7)	372
Increase (decrease) in cash, cash equivalents and restricted cash	91	(141)	(112)	290
Cash, cash equivalents and restricted cash at beginning of period	95	236	348	58
Cash, cash equivalents and restricted cash at end of period	$186	$95	$ 236	$ 348

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$124	$30
Restricted cash and cash equivalents	43	42
Accounts receivable, net		
Customer	453	486
Other	177	206
Inventories, net		
Gas held in storage	9	7
Materials and supplies	163	151
Regulatory assets	489	554
Other	75	75
Total current assets	1,533	1,551
Property, plant and equipment, net	13,446	12,498
Deferred debits and other assets		
Regulatory assets	2,312	2,493
Investments	130	132
Goodwill	4,005	4,005
Long-term note receivable	—	4
Prepaid pension asset	486	490
Deferred income taxes	12	4
Other	60	70
Total deferred debits and other assets	7,005	7,198
Total assets[(a)]	$21,984	$21,247

See the Combined Notes to Consolidated Financial Statements

239

Table of Contents

Pepco Holdings LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2018	2017
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$179	$350
Long-term debt due within one year	125	396
Accounts payable	496	348
Accrued expenses	256	261
Payables to affiliates	94	90
Regulatory liabilities	84	56
Unamortized energy contract liabilities	119	188
Customer deposits	116	119
Other	123	123
Total current liabilities	1,592	1,931
Long-term debt	6,134	5,478
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,146	2,070
Asset retirement obligations	52	16
Non-pension postretirement benefit obligations	103	105
Regulatory liabilities	1,864	1,872
Unamortized energy contract liabilities	442	561
Other	369	389
Total deferred credits and other liabilities	4,976	5,013
Total liabilities[(a)]	12,702	12,422
Commitments and contingencies		
Member's equity		
Membership interest	9,220	8,835
Undistributed gains (losses)	62	(10)
Total member's equity	9,282	8,825
Total liabilities and member's equity	$21,984	$21,247

(a) PHI’s consolidated total assets include $33 million and $41 million at December 31, 2018 and 2017, respectively, of PHI's consolidated VIE that can only be used to settle the liabilities of the VIE. PHI’s consolidated total liabilities include $69 million and $102 million at December 31, 2018 and 2017, respectively, of PHI's consolidated VIE for which the VIE creditors do not have recourse to PHI. See Note 2 - Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Pepco Holdings LLC and Subsidiary Companies
Consolidated Statements of Changes in Equity

(In millions, except share data)	Common Stock[(a)]	Retained Earnings	Accumulated Other Comprehensive Loss, net	Total Shareholders' Equity
Predecessor				
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 Gains/(Losses)	Accumulated Other Comprehensive Loss, net	Total Member's Equity
Balance, March 24, 2016[(b)]	$ 7,200	$ —	$ —	$ 7,200
Net loss	—	(61)	—	(61)
Distributions to member[(c)]	(400)	—	—	(400)
Contributions from member	1,251	—	—	1,251
Measurement period adjustment of Exelon’s deferred tax liabilities to reflect unitary state income tax consequences of the merger	35	—	—	35
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
Net Income	—	362	—	362
Distributions to member	—	(311)	—	(311)
Contributions from member	758	—	—	758
Balance, December 31, 2017	$ 8,835	$ (10)	$ —	$ 8,825
Net Income	—	398	—	398
Distributions to member	—	(326)	—	(326)
Contributions from member	385	—	—	385
Balance, December 31, 2018	$ 9,220	$ 62	$ —	$ 9,282

(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 5 — Mergers, Acquisitions and Dispositions.

See the Combined Notes to Consolidated Financial Statements

241

Table of Contents

Potomac Electric Power Company
Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2018	2017	2016
Operating revenues			
Electric operating revenues	$2,233	$2,126	$2,167
Revenues from alternative revenue programs	—	26	14
Operating revenues from affiliates	6	6	5
Total operating revenues	2,239	2,158	2,186
Operating expenses			
Purchased power	448	359	411
Purchased power from affiliates	206	255	295
Operating and maintenance	275	396	607
Operating and maintenance from affiliates	226	58	35
Depreciation and amortization	385	321	295
Taxes other than income	379	371	377
Total operating expenses	1,919	1,760	2,020
Gain on sales of assets	—	1	8
Operating income	320	399	174
Other income and (deductions)			
Interest expense, net	(128)	(121)	(127)
Other, net	31	32	36
Total other income and (deductions)	(97)	(89)	(91)
Income before income taxes	223	310	83
Income taxes	13	105	41
Net income	$210	$205	$42
Comprehensive income	$210	$205	$42

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Potomac Electric Power Company
Statements of Cash Flows

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Cash flows from operating activities			
Net income	$ 210	$ 205	$ 42
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization	385	321	295
Impairment losses on regulatory assets	—	14	—
Deferred income taxes and amortization of investment tax credits	(18)	113	153
Other non-cash operating activities	60	(6)	175
Changes in assets and liabilities:			
Accounts receivable	(5)	(20)	(41)
Receivables from and payables to affiliates, net	(17)	—	44
Inventories	(6)	(24)	1
Accounts payable and accrued expenses	59	(63)	32
Income taxes	(13)	81	110
Pension and non-pension postretirement benefit contributions	(17)	(72)	(32)
Other assets and liabilities	(164)	(142)	(128)
Net cash flows provided by operating activities	474	407	651
Cash flows from investing activities			
Capital expenditures	(656)	(628)	(586)
Purchases of investments	—	—	(30)
	2	—	—

Other investing activities			
Net cash flows used in investing activities	(654)	(628)	(616)
Cash flows from financing activities			
Changes in short-term borrowings	14	3	(41)
Issuance of long-term debt	200	202	4
Retirement of long-term debt	(14)	(13)	(11)
Dividends paid on common stock	(169)	(133)	(136)
Contributions from parent	166	161	187
Other financing activities	(4)	(1)	(3)
Net cash flows provided by financing activities	193	219	—
Increase (decrease) in cash, cash equivalents and restricted cash	13	(2)	35
Cash, cash equivalents and restricted cash at beginning of period	40	42	7
Cash, cash equivalents and restricted cash at end of period	$ 53	$ 40	$ 42

See the Combined Notes to Consolidated Financial Statements

243

Table of Contents

Potomac Electric Power Company
Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$16	$5
Restricted cash and cash equivalents	37	35
Accounts receivable, net		
Customer	225	250
Other	81	87
Receivables from affiliates	1	—
Inventories, net	93	87
Regulatory assets	270	213
Other	37	33
Total current assets	760	710
Property, plant and equipment, net	6,460	6,001
Deferred debits and other assets		
Regulatory assets	643	678
Investments	105	102
Prepaid pension asset	316	322
Other	15	19
Total deferred debits and other assets	1,079	1,121
Total assets	$8,299	$7,832

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Potomac Electric Power Company
Balance Sheets

(In millions)	December 31, 2018	2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$40	$26
Long-term debt due within one year	15	19
Accounts payable	214	139
Accrued expenses	126	137
Payables to affiliates	62	74
Regulatory liabilities	7	3
Customer deposits	54	54
Merger related obligation	38	42
Current portion of DC PLUG obligation	30	28
Other	42	28
Total current liabilities	628	550
Long-term debt	2,704	2,521
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,064	1,063
Non-pension postretirement benefit obligations	29	36
Regulatory liabilities	822	829
Other	312	300
Total deferred credits and other liabilities	2,227	2,228
Total liabilities	5,559	5,299
Commitments and contingencies		
Shareholder's equity		
Common stock	1,636	1,470
Retained earnings	1,104	1,063
Total shareholder's equity	2,740	2,533
Total liabilities and shareholder's equity	$8,299	$7,832

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Potomac Electric Power Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2015	$ 1,122	$ 1,118	$ 2,240
Net income	—	42	42
Common stock dividends	—	(169)	(169)
Contributions from parent	187	—	187
Balance, December 31, 2016	$ 1,309	$ 991	$ 2,300
Net income	—	205	205
Common stock dividends	—	(133)	(133)
Contributions from parent	161	—	161
Balance, December 31, 2017	$ 1,470	$ 1,063	$ 2,533
Net income	—	210	210
Common stock dividends	—	(169)	(169)
Contributions from parent	166	—	166
Balance, December 31, 2018	$ 1,636	$ 1,104	$ 2,740

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Delmarva Power & Light Company
Statements of Operations and Comprehensive Income (Loss)

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Operating revenues			
Electric operating revenues	$1,139	$1,125	$1,128
Natural gas operating revenues	181	161	148
Revenues from alternative revenue programs	4	6	(6)
Operating revenues from affiliates	8	8	7
Total operating revenues	1,332	1,300	1,277
Operating expenses			
Purchased power	352	282	369
Purchased fuel	89	71	60
Purchased power from affiliates	120	179	154
Operating and maintenance	182	283	422
Operating and maintenance from affiliates	162	32	19
Depreciation and amortization	182	167	157
Taxes other than income	56	57	55
Total operating expenses	1,143	1,071	1,236
Gain on sales of assets	1	—	9
Operating income	190	229	50
Other income and (deductions)			
Interest expense, net	(58)	(51)	(50)
Other, net	10	14	13
Total other income and (deductions)	(48)	(37)	(37)
Income before income taxes	142	192	13
Income taxes	22	71	22
Net income (loss)	$120	$121	$(9)
Comprehensive income (loss)	$120	$121	$(9)

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Delmarva Power & Light Company
Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2018	2017	2016
Cash flows from operating activities			
Net income (loss)	$120	$121	$(9)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization	182	167	157
Impairment losses on regulatory assets	—	6	—
Deferred income taxes and amortization of investment tax credits	24	89	109
Other non-cash operating activities	24	9	114
Changes in assets and liabilities:			
Accounts receivable	8	(22)	(5)
Receivables from and payables to affiliates, net	(9)	11	13
Inventories	(3)	(5)	—
Accounts payable and accrued expenses	11	(8)	(4)
Collateral received, net	—	—	1
Income taxes	2	26	28
Pension and non-pension postretirement benefit contributions	—	(2)	(22)
Other assets and liabilities	(7)	(71)	(72)
Net cash flows provided by operating activities	352	321	310
Cash flows from investing activities			
Capital expenditures	(364)	(428)	(349)
Other investing activities	2	(1)	13
Net cash flows used in investing activities	(362)	(429)	(336)
Cash flows from financing activities			
Change in short-term borrowings	(216)	216	(105)
Issuance of long-term debt	200	—	175
Retirement of long-term debt	(4)	(40)	(100)
Dividends paid on common stock	(96)	(112)	(54)
Contributions from parent	150	—	152
Other financing activities	(2)	—	(1)
Net cash flows provided by financing activities	32	64	67
Increase (decrease) in cash, cash equivalents and restricted cash	22	(44)	41
Cash, cash equivalents and restricted cash at beginning of period	2	46	5
Cash, cash equivalents and restricted cash at end of period	$24	$2	$46

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Delmarva Power & Light Company
Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$23	$2
Restricted cash and cash equivalents	1	—
Accounts receivable, net		
Customer	134	146
Other	46	38
Inventories, net		
Gas held in storage	9	7
Materials and supplies	37	36
Regulatory assets	59	69
Other	27	27
Total current assets	336	325
Property, plant and equipment, net	3,821	3,579
Deferred debits and other assets		
Regulatory assets	231	245
Goodwill	8	8
Prepaid pension asset	186	193
Other	6	7
Total deferred debits and other assets	431	453
Total assets	$4,588	$4,357

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Delmarva Power & Light Company
Balance Sheets

	December 31,	
(In millions)	2018	2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$—	$216
Long-term debt due within one year	91	83
Accounts payable	111	82
Accrued expenses	39	35
Payables to affiliates	33	46
Regulatory liabilities	59	42
Customer deposits	35	35
Other	7	8
Total current liabilities	375	547
Long-term debt	1,403	1,217
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	628	603
Non-pension postretirement benefit obligations	17	14
Regulatory liabilities	606	593
Other	50	48
Total deferred credits and other liabilities	1,301	1,258
Total liabilities	3,079	3,022
Commitments and contingencies		
Shareholder's equity		
Common stock	914	764
Retained earnings	595	571
Total shareholder's equity	1,509	1,335
Total liabilities and shareholder's equity	$4,588	$4,357

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Delmarva Power & Light Company
Statements of Changes in Shareholder's Equity

(In millions)	Common Stock	Retained Earnings	Total Shareholder's Equity
Balance, December 31, 2015	$ 612	$ 625	$ 1,237
Net loss	—	(9)	(9)
Common stock dividends	—	(54)	(54)
Contributions from parent	152	—	152
Balance, December 31, 2016	$ 764	$ 562	$ 1,326
Net income	—	121	121
Common stock dividends	—	(112)	(112)
Balance, December 31, 2017	$ 764	$ 571	$ 1,335
Net income	—	120	120
Common stock dividends	—	(96)	(96)
Contributions from parent	150	—	150
Balance, December 31, 2018	$ 914	$ 595	$ 1,509

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Operations and Comprehensive Income (Loss)

	For the Years Ended December 31,		
(In millions)	2018	2017	2016
Operating revenues			
Electric operating revenues	$1,237	$1,176	$1,245
Revenues from alternative revenue programs	(4)	8	9
Operating revenues from affiliates	3	2	3
Total operating revenues	1,236	1,186	1,257
Operating expenses			
Purchased power	587	541	614
Purchased power from affiliates	29	29	37
Operating and maintenance	188	279	410
Operating and maintenance from affiliates	142	28	18
Depreciation and amortization	136	146	165
Taxes other than income	5	6	7
Total operating expenses	1,087	1,029	1,251
Gain on sale of assets	—	—	1
Operating income	149	157	7
Other income and (deductions)			
Interest expense, net	(64)	(61)	(62)
Other, net	2	7	9
Total other income and (deductions)	(62)	(54)	(53)
Income (loss) before income taxes	87	103	(46)
Income taxes	12	26	(4)
Net income (loss)	$75	$77	$(42)
Comprehensive income (loss)	$75	$77	$(42)

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Atlantic City Electric Company and Subsidiary Company
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2018	2017	2016
Cash flows from operating activities			
Net income (loss)	$75	$77	$(42)
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Depreciation and amortization	136	146	165
Impairment losses on regulatory assets	—	7	—
Deferred income taxes and amortization of investment tax credits	25	32	22
Other non-cash operating activities	24	17	155
Changes in assets and liabilities:			
Accounts receivable	(8)	14	(8)
Receivables from and payables to affiliates, net	1	—	13
Inventories	(4)	(7)	(1)
Accounts payable and accrued expenses	(7)	(2)	9
Income taxes	(2)	(11)	174
Pension and non-pension postretirement benefit contributions	(6)	(20)	(17)
Other assets and liabilities	(6)	(47)	(85)
Net cash flows provided by operating activities	228	206	385
Cash flows from investing activities			
Capital expenditures	(335)	(312)	(311)
Other investing activities	1	(1)	4
Net cash flows used in investing activities	(334)	(313)	(307)
Cash flows from financing activities			
Change in short-term borrowings	(94)	108	(5)
Proceeds from short-term borrowings with maturities greater than 90 days	125	—	—
Issuance of long-term debt	350	—	—
Retirement of long-term debt	(281)	(35)	(48)
Dividends paid on common stock	(59)	(68)	(63)
Contributions from parent	67	—	139
Other financing activities	(3)	—	(1)
Net cash flows provided by financing activities	105	5	22
(Decrease) increase in cash, cash equivalents and restricted cash	(1)	(102)	100
Cash, cash equivalents and restricted cash at beginning of period	31	133	33
Cash, cash equivalents and restricted cash at end of period	$30	$31	$133

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

	December 31,	
(In millions)	2018	2017
ASSETS		
Current assets		
Cash and cash equivalents	$7	$2
Restricted cash and cash equivalents	4	6
Accounts receivable, net		
Customer	95	92
Other	55	56
Receivables from affiliates	1	—
Inventories, net	33	29
Regulatory assets	40	71
Other	5	2
Total current assets	240	258
Property, plant and equipment, net	2,966	2,706
Deferred debits and other assets		
Regulatory assets	386	359
Long-term note receivable	—	4
Prepaid pension asset	67	73
Other	40	45
Total deferred debits and other assets	493	481
Total assets[(a)]	$3,699	$3,445

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Atlantic City Electric Company and Subsidiary Company
Consolidated Balance Sheets

(In millions)	December 31, 2018	2017
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current liabilities		
Short-term borrowings	$139	$108
Long-term debt due within one year	18	281
Accounts payable	154	118
Accrued expenses	35	33
Payables to affiliates	28	29
Regulatory liabilities	18	11
Customer deposits	26	31
Other	4	8
Total current liabilities	422	619
Long-term debt	1,170	840
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	535	493
Non-pension postretirement benefit obligations	17	14
Regulatory liabilities	402	411
Other	27	25
Total deferred credits and other liabilities	981	943
Total liabilities[a]	2,573	2,402
Commitments and contingencies		
Shareholder's equity		
Common stock	979	912
Retained earnings	147	131
Total shareholder's equity	1,126	1,043
Total liabilities and shareholder's equity	$3,699	$3,445

(a) ACE’s consolidated assets include $23 million and $29 million at December 31, 2018 and 2017, respectively, of ACE’s consolidated VIE that can only be used to settle the liabilities of the VIE. ACE’s consolidated liabilities include $59 million and $90 million at December 31, 2018 and 2017, respectively, of ACE’s consolidated VIE for which the VIE creditors do not have recourse to ACE. See Note 2 - Variable Interest Entities for additional information.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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, 2015	$ 773	$ 227	$ 1,000
Net loss	—	(42)	(42)
Common stock dividends	—	(63)	(63)
Contributions from parent	139	—	139
Balance, December 31, 2016	$ 912	$ 122	$ 1,034
Net income	—	77	77
Common stock dividends	—	(68)	(68)
Balance, December 31, 2017	$ 912	$ 131	$ 1,043
Net income	—	75	75
Common stock dividends	—	(59)	(59)
Contribution from parent	67	—	67
Balance, December 31, 2018	$ 979	$ 147	$ 1,126

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)
Index to Combined Notes to Consolidated Financial Statements
The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the Registrants to which the footnotes apply:
Applicable Notes

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
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	•	•	•	•	•	•	•		•	•	•	•	•	•	•	•	•	•	•			•	•	•	•	•	

257

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

1. Significant Accounting Policies (All Registrants)
Description of Business (All Registrants)
Exelon is a utility services holding company engaged in the generation, delivery and marketing of energy through Generation and the energy distribution and transmission businesses through ComEd, PECO, BGE, Pepco, DPL and ACE. On March 23, 2016, Exelon completed the merger with PHI, which became 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. See Note 5 — Mergers, Acquisitions and Dispositions for additional information regarding the merger transaction.

Name of Registrant	Business	Service Territories
Exelon Generation Company, LLC	Generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity to both wholesale and retail customers. Generation also sells natural gas, renewable energy and other energy-related products and services.	Six reportable segments: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions
Commonwealth Edison Company	Purchase and regulated retail sale of electricity	Northern Illinois, including the City of Chicago
	Transmission and distribution of electricity to retail customers	
PECO Energy Company	Purchase and regulated retail sale of electricity and natural gas	Southeastern Pennsylvania, including the City of Philadelphia (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Pennsylvania counties surrounding the City of Philadelphia (natural gas)
Baltimore Gas and Electric Company	Purchase and regulated retail sale of electricity and natural gas	Central Maryland, including the City of Baltimore (electricity and natural gas)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	
Pepco Holdings LLC	Utility services holding company engaged, through its reportable segments Pepco, DPL and ACE	Service Territories of Pepco, DPL and ACE
Potomac Electric Power Company	Purchase and regulated retail sale of electricity	District of Columbia, and major portions of Montgomery and Prince George's Counties, Maryland.
	Transmission and distribution of electricity to retail customers	
Delmarva Power & Light Company	Purchase and regulated retail sale of electricity and natural gas	Portions of Delaware and Maryland (electricity)
	Transmission and distribution of electricity and distribution of natural gas to retail customers	Portions of New Castle County, Delaware (natural gas)
Atlantic City Electric Company	Purchase and regulated retail sale of electricity	Portions of Southern New Jersey

Transmission and distribution of electricity to retail customers

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.

As a result of the merger with 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 it has pushed-down to the consolidated financial statements of PHI such that the assets and liabilities of PHI are 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 results of operations and the financial positions 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.

Table of Contents

For financial statement purposes, beginning on March 24, 2016, disclosures related to Exelon also apply to PHI, Pepco, DPL and ACE, 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. PHI also has a business services subsidiary, PHISCO, which provides a variety of support services at cost, including legal, accounting, engineering, customer operations, distribution and transmission planning, asset management, system operations, and power procurement, to PHI operating companies. The costs of BSC and PHISCO are directly charged or allocated to the applicable subsidiaries. The results of Exelon’s corporate operations are presented as “Other” within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of Generation, PECO, BGE and PHI and more than 99% of ComEd. PHI owns 100% of Pepco, DPL and ACE. Generation owns 100% of its significant consolidated subsidiaries, either directly or indirectly, except for certain consolidated VIEs, including CENG and EGRP, of which Generation holds a 50.01% and 51% interest, respectively. The remaining interests in these consolidated VIEs are included in noncontrolling interests on Exelon’s and Generation’s Consolidated Balance Sheets. See Note 2 — Variable Interest Entities for additional information 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. Where the Registrants do not have a controlling financial interest in an entity, proportionate consolidation, equity method accounting or accounting for investments in equity securities without readily determinable fair value 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 and PECO. Under equity method accounting, 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 accounting for investments in equity securities without readily determinable fair values if they lack significant influence, which generally results when they hold less than 20% of the common stock of an entity. Under accounting for investments in equity securities without readily determinable fair values, the Registrants report their investments at cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment. Changes in measurement are reported in earnings.

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.

Prior Period Adjustments and Reclassifications (All Registrants)

Certain prior year amounts in the Registrants' Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholders' Equity have been recasted to reflect new accounting standards issued by the FASB and adopted as of January 1, 2018. See New Accounting Standards below for additional information.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Accounting for the Effects of Regulation (Exelon and the Utility Registrants)
For their regulated electric and gas operations, Exelon and the Utility Registrants reflect the effects of cost-based rate regulation in their financial statements, which is required 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 designed to recover costs can be charged to and collected 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, PAPUC, MDPSC, DCPSC, DPSC and 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's regulatory assets and liabilities as of the balance sheet date are probable of being recovered or settled in future rates. 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 financial statements. See Note 4 — Regulatory Matters for additional information.
With the exception of income tax-related regulatory assets and liabilities, Exelon and the Utility Registrants classify regulatory assets and liabilities with a recovery or settlement period greater than one year as both current and non-current in their Consolidated Balance Sheets, with the current portion representing the amount expected to be recovered from or settled to customers over the next twelve-month period as of the balance sheet date. Income tax-related regulatory assets and liabilities are classified entirely as non-current in Exelon's and the Utility Registrants' Consolidated Balance Sheets to align with the classification of the related deferred income tax balances.
Exelon and the Utility 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. The Registrants' operating revenues generally consist of revenues from contracts with customers involving the sale and delivery of energy commodities and related products and services, utility revenues from alternative revenue programs (ARP), and realized and unrealized revenues recognized under mark-to-market energy commodity derivative contracts. The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers in an amount that the entities expect to be entitled to in exchange for those goods or services. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and natural gas tariff sales, distribution and transmission services. 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 ARP revenue for its best estimate of the electric distribution, energy efficiency, and transmission revenue impacts resulting from future changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE, Pepco and DPL record ARP revenue for their best estimate of the electric and natural gas distribution revenue impacts resulting from future changes in rates that they believe are probable of approval by the MDPSC and/or DCPSC in accordance with their revenue decoupling mechanisms. PECO, BGE, Pepco, DPL and ACE record ARP revenue for their best estimate of the transmission revenue impacts resulting from future changes in rates that they believe are probable of approval by FERC in accordance with their formula rate mechanisms. See Note 4 — Regulatory Matters and Note 23 — Supplemental Financial Information for additional information.
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. To the 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 in its Consolidated Balance Sheets. See Note 4 — Regulatory Matters and Note 12 — Derivative Financial Instruments for additional information.

Table of Contents

Taxes Directly Imposed on Revenue-Producing Transactions. 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 23 — 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.

Income Taxes (All Registrants)

Deferred Federal and state income taxes are recorded on significant temporary differences between the book and tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred in the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. 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 in their Consolidated Statements of Operations and Comprehensive Income.

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 14 — Income Taxes for additional information.

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, 2018 and 2017, the Registrants' restricted cash and cash equivalents primarily represented the following items:

Registrant	Description
Exelon	Payment of medical, dental, vision and long-term disability benefits, in addition to the items listed for Generation and the Utility Registrants.
Generation	Project-specific nonrecourse financing structures for debt service and financing of operations of the underlying entities.
ComEd	Collateral held from suppliers associated with energy and REC procurement contracts, any over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA and costs for the remediation of an MGP site.
PECO	Proceeds from the sales of assets that were subject to PECO's mortgage indenture.
BGE	Proceeds from the loan program for the completion of certain energy efficiency measures and collateral held from energy suppliers.
PHI	Payment of merger commitments, collateral held from its energy suppliers associated with procurement contracts and repayment of transition bonds.
Pepco	Payment of merger commitments and collateral held from energy suppliers.

DPL	Collateral held from energy suppliers.
ACE	Repayment of transition bonds and collateral held from energy suppliers.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Restricted cash and cash equivalents not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2018 and 2017, the Registrants' noncurrent restricted cash and cash equivalents primarily represented ComEd's over-recovered RPS costs and alternative compliance payments received from RES pursuant to FEJA and costs for the remediation of an MGP site, and ACE's repayment of transition bonds.
See Note 23 — Supplemental Financial Information for additional information.
Allowance for Uncollectible Accounts (All Registrants)
The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the customers' accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. Utility Registrants estimate the allowance by applying loss rates developed specifically for each company to the outstanding receivable balance by customer risk segment. Utility Registrants' customer accounts are written off consistent with approved regulatory requirements. See Note 4 — Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd and ACE.
Variable Interest Entities (All Registrants)
Exelon accounts for its investments in and arrangements with VIEs based on 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,
- 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, materials and supplies, and emissions allowances are generally included in inventory when purchased. Fossil fuel and emissions allowances are expensed to purchased power and fuel expense when used or sold. Materials and supplies generally includes transmission, distribution and generating plant materials and are expensed to operating and maintenance or capitalized to property, plant and equipment, as appropriate, when installed or used.
Debt and Equity Security Investments (Exelon and Generation)
Debt Security Investments. Debt securities are reported at fair value and classified as available-for-sale securities. Unrealized gains and losses, net of tax, are reported in OCI.
Equity Security Investments without Readily Determinable Fair Values. Exelon has certain equity securities without readily determinable fair values. Exelon has elected to use the practicability exception to measure these investments, defined as cost adjusted for changes from observable transactions for identical or similar investments of the same issuer, less impairment. Changes in measurement are reported in earnings.
Equity Security Investments with Readily Determinable Fair Values. Equity securities held in the NDT funds are classified as equity securities with readily determinable fair values. 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. Exelon's and Generation's NDT funds are classified as current or noncurrent assets, depending on the timing of the decommissioning activities and income taxes on trust earnings. See Note 4 — Regulatory Matters for additional information regarding ComEd's and PECO's regulatory assets and liabilities and Note 11 —

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Fair Value of Financial Assets and Liabilities and Note 15 — Asset Retirement Obligations for additional 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, Exelon Corporate and PHI and AFUDC for regulated property at the Utility Registrants. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to Operating and 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, net. DOE SGIG and other funds reimbursed to the Utility Registrants 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 and group methods 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 consistent with the composite and group methods of depreciation. Depreciation expense at ComEd, BGE, Pepco, DPL and ACE includes the estimated cost of dismantling and removing plant from service upon retirement. Actual incurred removal costs are applied against a related regulatory liability or recorded to a regulatory asset if in excess of previously collected removal costs. 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.

Capitalized Software. Certain costs, such as design, coding, and testing 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 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.

Capitalized Interest and AFUDC. 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.

AFUDC is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to an allowance 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.

See Note 6 — Property, Plant and Equipment, Note 9 — Jointly Owned Electric Utility Plant and Note 23 — 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. Any potential future SNF disposal fees will be expensed through fuel expense. Additionally, 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 22 — Commitments and Contingencies for additional information regarding the cost of SNF storage and disposal.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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.
Depreciation 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 group, composite or unitary methods of depreciation. The group approach is typically for groups of similar assets that have approximately the same useful lives and the composite approach is used for dissimilar assets that have different lives. Under both methods, a reporting entity depreciates the assets over the average life of the assets in the 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 Registrants are based on a combination of depreciation studies, historical retirements, site licenses and management estimates of operating costs and expected future energy market conditions. See Note 8 — Early Plant Retirements for additional information on the impacts of expected and potential early plant retirements.
See Note 6 — Property, Plant and Equipment for additional 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 Utility Registrants’ Consolidated Statements of Operations and Comprehensive Income. Amortization of ComEd’s electric distribution and energy efficiency formula rate regulatory assets and the Utility Registrants' transmission formula rate regulatory assets is recorded to Operating revenues.
Amortization of income tax related regulatory assets and liabilities is 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 4 — Regulatory Matters and Note 23 — Supplemental Financial Information for additional information regarding Generation’s nuclear fuel and ARC, and the amortization of the Utility Registrants' regulatory assets.
Asset Retirement Obligations (All Registrants)
Generation estimates and recognizes a liability for its legal obligation to perform asset retirement activities even though the timing and/or methods of settlement may be conditional on future events. Generation generally updates its nuclear decommissioning ARO annually, unless circumstances warrant more frequent updates, based on its annual evaluation of cost escalation factors and probabilities assigned to the multiple outcome scenarios within its probability-weighted discounted cash flow models. Generation’s multiple outcome scenarios are generally based on decommissioning cost studies which are updated, on a rotational basis, for each of Generation’s nuclear units at least every five years, unless circumstances warrant more frequent updates. 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 15 — Asset Retirement Obligations for additional information.
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

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

amortization method over the term of the guarantee. See Note 22 — Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets (All Registrants). 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 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. See Note 7 — Impairment of Long-Lived Assets and Intangibles for additional information.

Goodwill (Exelon, ComEd and PHI). Goodwill represents the excess of the purchase price paid over the estimated fair value of the net 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 10 — Intangible Assets for additional information.

Equity Method Investments (Exelon and Generation). 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 entity 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 Security Investments (Exelon and Generation). Declines in the fair value of debt security investments below the cost basis are reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the amount of the impairment loss is included in earnings.

Equity Security Investments (Exelon and Generation). Equity investments with readily determinable fair values are measured and recorded at fair value with any changes in fair value recorded through earnings. Investments in equity securities without readily determinable fair values are qualitatively assessed for impairment each reporting period. If it is determined that the equity security is impaired on the basis of the qualitative assessment, an impairment loss will be recognized in earnings to the amount by which the security’s carrying amount exceeds its fair value.

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. For derivatives intended to serve as economic hedges, changes in fair value are recognized in earnings each period. Amounts classified in earnings are included in Operating revenue, Purchased power and fuel, Interest expense or Other, net in the Consolidated Statements of Operations and Comprehensive Income based on the activity the transaction is economically hedging. While the majority of the derivatives serve as economic hedges, there are also derivatives entered into for proprietary trading purposes, subject to Exelon’s Risk Management Policy, and changes in the fair value of those derivatives are recorded in revenue in the Consolidated Statements of Operations and Comprehensive Income. At the Utility Registrants, 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. 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. On July 1, 2018, Exelon and Generation de-designated its fair value and cash flow hedges. See Note 4 — Regulatory Matters and Note 12 — Derivative Financial Instruments for additional information.

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

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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 12 — 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 assumptions, and accounting elections. 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 16 — Retirement Benefits for additional information.

New Accounting Standards (All Registrants)

New Accounting Standards Adopted in 2018: In 2018, the Registrants adopted the following new authoritative accounting guidance issued by the FASB.

Defined Benefit Plan Disclosures (Issued August 2018). Eliminates existing disclosure requirements related to amounts in Accumulated other comprehensive income expected to be recognized in Net periodic benefit cost over the next year and the effects of a one-percentage-point change in the assumed health care cost trend rates. In addition, new disclosures were added such as the weighted-average interest crediting rates for cash balance plans and an explanation for the reasons for significant gains and losses related to changes in the benefit obligation. The standard is effective January 1, 2021, with early adoption permitted, and must be applied retrospectively. Exelon early adopted this standard in the fourth quarter of 2018. See Note 16 — Retirement Benefits for additional information.

Fair Value Measurement Disclosures (Issued August 2018). Updates the disclosure requirements for fair value measurements to improve the usefulness of information for financial statement users. The guidance removes the requirements to disclose (1) the amount of and reasons for transfers between Level 1 and Level 2, (2) the policy for timing of transfers between levels, and (3) the valuation processes for Level 3 fair value measurements and adds a requirement to disclose the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. The standard is effective January 1, 2020, with early adoption permitted. The amendments to remove disclosures must be applied retrospectively and can be early adopted, while the amendments to add disclosures must be applied prospectively and adoption can be delayed until the effective date. The Registrants early adopted, in the fourth quarter of 2018, the amendments to remove disclosures and will adopt the amendments to add disclosures in the first quarter of 2020. The impact of the new disclosures is not expected to be material to the Registrants’ consolidated financial statements. See Note 11 — Fair Value of Financial Assets and Liabilities for additional information.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income (Issued February 2018). Provides an election for a reclassification from AOCI to Retained earnings to eliminate the stranded tax effects resulting from the TCJA. This standard is effective January 1, 2019, with early adoption permitted, and may be applied either in the period of adoption or retrospective to each period in which the effects of the TCJA were recognized. Exelon early adopted this standard and elected to apply the guidance retrospectively as of December 31, 2017, which resulted in an increase to Exelon’s Retained earnings and Accumulated other comprehensive loss of $539 million in its Consolidated Balance Sheet and Consolidated Statement of Changes in Shareholders' Equity related to deferred income taxes associated with Exelon’s pension and OPEB obligations. There was no impact for Generation or the Utility Registrants. Exelon's accounting policy is to release the stranded tax effects from AOCI related to its pension and OPEB plans under a portfolio (or aggregate) approach as an entire pension or OPEB plan is liquidated or terminated. See Note 21— Changes in Accumulated Other Comprehensive Income for additional information.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Issued March 2017). Changes the accounting and presentation of pension and OPEB costs at the plan sponsor (i.e., Exelon) level. The guidance requires plan sponsors to report the service cost and other non-service cost components of net periodic pension cost and net periodic OPEB cost (together, net benefit cost) separately. Under the new guidance, service cost is presented as part of income from operations and the other non-service cost components are classified outside of income from operations in the Consolidated Statements of Operations and Comprehensive Income. Additionally, service cost is the only component eligible for capitalization on a prospective basis beginning on January 1, 2018. Under prior GAAP, the total amount of net benefit cost was recorded as part of income from operations and all components were eligible for capitalization. Exelon applied the presentation of the service component and the other non-service cost components of net benefit costs retrospectively and, accordingly, have recasted those amounts, which were not material, in its Consolidated Statement of Operations and Comprehensive Income in prior periods presented. Exelon elected the practical expedient that permits an employer to use the amounts disclosed in its pension and other postretirement benefit plan note for the comparative periods as the estimation basis for applying the retrospective presentation requirements. In Exelon’s consolidated financial statements, non-service cost components of pension and OPEB cost capitalizable under a regulatory framework were prospectively reported as regulatory assets (previously, they were capitalizable under pension and OPEB accounting guidance and reported as PP&E). These regulatory assets are amortized outside of operating income. See Note 16 — Retirement Benefits for additional information.

Generation, ComEd, PECO, BGE, BSC, PHI, Pepco, DPL, ACE and PHISCO participate in Exelon’s single employer pension and OPEB plans and apply multi-employer accounting. Multi-employer accounting was not impacted by this standard; therefore, Exelon's subsidiary financial statements did not change upon its adoption.

Statement of Cash Flows: Classification of Restricted Cash (Issued November 2016). The standard 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). The Registrants applied the new guidance using the full retrospective method and, accordingly, have recasted the presentation of restricted cash in their Consolidated Statements of Cash Flows in the prior periods presented. See Note 23 — Supplemental Financial Information for additional information.

Recognition and Measurement of Financial Assets and Financial Liabilities (Issued January 2016). Eliminates the available-for-sale and cost method classification for equity securities and requires that all equity investments (other than those accounted for using the equity method of accounting) be measured and recorded at fair value with any changes in fair value recorded through earnings and, for equity investments without a readily determinable fair value, provides a measurement alternative of cost less impairment plus or minus adjustments for observable price changes in identical or similar assets. In addition, equity investments without readily determinable fair values must be qualitatively assessed for impairment each reporting period and fair value determined if any significant impairment indicators exist. If fair value is less than carrying value, the impairment is recorded through net income immediately in the period in which it is identified. The guidance does not impact the classification or measurement of investments in debt securities. The guidance also amends several disclosure requirements, including requiring i) financial assets and financial liabilities to be presented separately in the balance sheet or note, grouped by measurement category and form, ii) disclosure of 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 iii) for financial assets and liabilities measured at amortized cost, disclosure of the fair value of the amount that would be received to sell the asset or paid to transfer the liability. The guidance was applied using a modified retrospective transition approach with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption. The Registrants recorded an insignificant adjustment to opening retained earnings as of January 1, 2018 related to unrealized gains/losses on available for sale equity securities. See Note 21— Changes in Accumulated Other Comprehensive Income for additional information.

Revenue from Contracts with Customers (Issued May 2014 and subsequently amended to address implementation questions). Changes the criteria for recognizing revenue from a contract with a customer. The new standard replaces existing guidance on revenue recognition, including most industry specific guidance, with a five-step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries, and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing, and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants applied the new guidance using the full retrospective method

Table of Contents

and, accordingly, have recasted certain amounts in their Consolidated Statements of Operations and Comprehensive Income, Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Changes in Shareholders' Equity and Combined Notes to Consolidated Financial Statements in the prior periods presented. The amounts recasted in the Registrants' 2017 and 2016 Consolidated Statements of Operations and Comprehensive Income are shown in the table below. The amounts recasted in the Registrants’ Consolidated Statements of Cash Flows, Consolidated Balance Sheets, Consolidated Statements of Changes in Shareholders' Equity and Combined Notes to Consolidated Financial Statements were not material. See Note 3 — Revenue from Contracts with Customers for additional information.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

						Successor			
For the year ended December 31, 2017	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Operating Revenues - As reported									
Competitive business revenues	$17,360	$ —	$—	$—	$—	$ —	$—	$—	$—
Rate-regulated utility revenues	16,171	—	—	—	—	—	—	—	—
Operating revenues	—	17,351	—	—	—	—	—	—	—
Electric operating revenues	—	—	5,521	2,369	2,484	4,468	2,152	1,131	1,184
Natural gas operating revenues	—	—	—	494	676	161	—	161	—
Operating revenues from affiliates	—	1,115	15	7	16	50	6	8	2
Total operating revenues	$33,531	$ 18,466	$5,536	$2,870	$3,176	$ 4,679	$2,158	$1,300	$1,186
Operating Revenues - Adjustments									
Competitive business revenues	$34	$ —	$—	$—	$—	$ —	$—	$—	$—
Rate-regulated utility revenues	(207)	—	—	—	—	—	—	—	—
Operating revenues	—	34	—	—	—	—	—	—	—
Electric operating revenues	—	—	(43)	—	(100)	(40)	(26)	(6)	(8)
Natural gas operating revenues	—	—	—	—	(24)	—	—	—	—
Revenues from alternative revenue programs	207	—	43	—	124	40	26	6	8
Operating revenues from affiliates	—	—	—	—		—	—	—	—
Total operating revenues	$34	$ 34	$—	$—	$—	$ —	$—	$—	$—
Operating Revenues - Retrospective application									
Competitive business revenues	$17,394	$ —	$—	$—	$—	$ —	$—	$—	$—
Rate-regulated utility revenues	15,964	—	—	—	—	—	—	—	—
Operating revenues	—	17,385	—	—	—	—	—	—	—
Electric operating revenues	—	—	5,478	2,369	2,384	4,428	2,126	1,125	1,176
Natural gas operating revenues	—	—	—	494	652	161	—	161	—
Revenues from alternative revenue programs	207	—	43	—	124	40	26	6	8
Operating revenues from affiliates	—	1,115	15	7	16	50	6	8	2
Total operating revenues	$33,565	$ 18,500	$5,536	$2,870	$3,176	$ 4,679	$2,158	$1,300	$1,186

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

									Successor March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016
For the year ended December 31, 2016	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Operating Revenues - As reported										
Competitive business revenues	$16,324	$—	$—	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	15,036	—	—	—	—	—	—	—	—	—
Operating revenues	—	16,312	—	—	—	—	—	—	—	—
Electric operating revenues	—	—	5,239	2,524	2,603	2,181	1,122	1,254	3,506	1,096
Natural gas operating revenues	—	—	—	462	609	—	148	—	92	57
Operating revenues from affiliates	—	1,439	15	8	21	5	7	3	45	—
Total operating revenues	$31,360	$ 17,751	$5,254	$2,994	$3,233	$2,186	$1,277	$1,257	$ 3,643	$ 1,153
Operating Revenues - Adjustments										
Competitive business revenues	$6	$—	$—	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	(48)	—	—	—	—	—	—	—	—	—
Operating revenues	—	6	—	—	—	—	—	—	—	—
Electric operating revenues	—	—	24	—	(72)	(14)	6	(9)	(43)	26
Natural gas operating revenues	—	—	—	—	19	—	—	—	—	—
Revenues from alternative revenue programs	48	—	(24)	—	53	14	(6)	9	43	(26)
Operating revenues from affiliates	—	—	—	—	—	—	—	—	—	—
Total operating revenues	$6	$ 6	$—	$—	$—	$—	$—	$—	$—	$—
Operating Revenues - Retrospective										

application										
Competitive business revenues	$16,330	$—	$—	$—	$—	$—	$—	$—	$—	$—
Rate-regulated utility revenues	14,988	—	—	—	—	—	—	—	—	—
Operating revenues	—	16,318	—	—	—	—	—	—	—	—
Electric operating revenues	—	—	5,263	2,524	2,531	2,167	1,128	1,245	3,463	1,122
Natural gas operating revenues	—	—	—	462	628	—	148	—	92	57
Revenues from alternative revenue programs	48	—	(24)	—	53	14	(6)	9	43	(26)
Operating revenues from affiliates	—	1,439	15	8	21	5	7	3	45	—
Total operating revenues	$31,366	$ 17,757	$5,254	$2,994	$3,233	$2,186	$1,277	$1,257	$ 3,643	$ 1,153

270

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

New Accounting Standards Adopted as of January 1, 2019: The following new authoritative accounting guidance issued by the FASB was adopted as of January 1, 2019 and will be reflected by the Registrants in their consolidated financial statements beginning in the first quarter of 2019.

Cloud Computing Arrangements (Issued August 2018). Aligns the requirements for capitalizing costs incurred to implement a cloud computing arrangement with the internal-use software guidance. As a result, certain implementation costs incurred in a cloud computing arrangement that are currently expensed as incurred will be deferred and amortized over the non-cancellable term of the arrangement plus any reasonably certain renewal periods. The standard is effective January 1, 2020, with early adoption permitted, and can be applied using either a prospective or retrospective transition approach. A retrospective approach requires a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. The Registrants early adopted this standard using a prospective approach as of January 1, 2019. The new guidance is not expected to have a material impact on the Registrants' financial statements.

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 Registrants adopted the standard on January 1, 2019.

The new standard requires lessees to recognize both the right-of-use assets and lease liabilities in the balance sheet for most leases, whereas under previous GAAP only finance lease liabilities (referred to as capital leases) were recognized in the balance sheet. In addition, the definition of a lease has been revised which may result in changes to the classification of an arrangement as a lease. Under the new standard, an arrangement that conveys the right to control the use of an identified asset by obtaining substantially all of its economic benefits and directing how it is used is a lease, whereas the previous definition focuses on the ability to control the use of the asset or to obtain its output. Quantitative and qualitative disclosures related to the amount, timing and judgments of an entity's accounting for leases and the related cash flows are expanded. Disclosure requirements apply to both lessees and lessors, whereas previous disclosures related only to lessees. The recognition, measurement, and presentation of expenses and cash flows arising from a lease by a lessee have not significantly changed from previous GAAP. Lessor accounting is also largely unchanged.

The new standard provides a number of transition practical expedients, which the Registrants have elected, including:

- a "package of three" expedients that must be taken together and allow entities to (1) not reassess whether existing contracts contain leases, (2) carryforward the existing lease classification, and (3) not reassess initial direct costs associated with existing leases,
- an implementation expedient which allows the requirements of the standard in the period of adoption with no restatement of prior periods, and
- a land easement expedient which allows entities to not evaluate land easements under the new standard at adoption if they were not previously accounted for as leases.

The Registrants have assessed the lease standard and executed a detailed implementation plan in preparation for adoption, which included the following key activities:

- Developed a complete lease inventory and abstracted the required data attributes into a lease accounting system that supports the Registrants' lease portfolios and integrates with existing systems.
- Evaluated the transition practical expedients available under the standard.
- Identified, assessed and documented technical accounting issues, policy considerations and financial reporting implications.
- Identified and implemented changes to processes and controls to ensure all impacts of the new standard are effectively addressed.

The adoption of the new standard is expected to result in right of use assets and lease obligations for operating leases recorded in the Registrants' Consolidated Balance Sheets on January 1, 2019 of approximately:

271

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
ROU Assets	$1,400-$1,500	$1,000-$1,100	$5-$10	$1-$5	$100-$120	$250-$270	$60-$65	$70-$75	$20-$25
Lease Liabilities	$1,600-$1,700	$1,200-$1,300	$5-$10	$1-$5	$100-$120	$300-$320	$60-$65	$75-$80	$20-$25

The impact of adopting the new standard on retained earnings as of January 1, 2019 is expected to be immaterial.

New Accounting Standards Issued and Not Yet Adopted as of December 31, 2018: 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 as of December 31, 2018. Unless otherwise indicated, the Registrants are currently assessing the impacts such guidance may have (which could be material) in 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 that such standards will not significantly impact the Registrants' financial reporting.

Goodwill Impairment (Issued January 2017). Simplifies the accounting for goodwill impairment by removing Step 2 of the current test, which requires calculation of a hypothetical purchase price allocation. Under the revised guidance, goodwill impairment will be measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill (currently Step 1 of the two-step impairment test). Entities will continue to have the option to perform a qualitative assessment to determine if a quantitative impairment test is necessary. Exelon, Generation, ComEd, PHI and DPL have goodwill as of December 31, 2018. This updated guidance is not currently expected to impact the Registrants' financial reporting. The standard is effective January 1, 2020, with early adoption permitted, and must be applied on a prospective basis.

Impairment of Financial Instruments (Issued June 2016). Provides for a new Current Expected Credit Loss (CECL) impairment model for specified financial instruments including loans, trade receivables, debt securities classified as held-to-maturity investments and net investments in leases recognized by a lessor. Under the new guidance, on initial recognition and at each reporting period, an entity is required to recognize an allowance that reflects the entity's current estimate of credit losses expected to be incurred over the life of the financial instrument. The standard does not make changes to the existing impairment models for non-financial assets such as fixed assets, intangibles and goodwill. The standard will be effective January 1, 2020 (with early adoption as of January 1, 2019 permitted) and requires a modified retrospective transition approach through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. The Registrants are currently assessing the impacts of this standard.

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, 2018 and 2017, Exelon, Generation, PHI and ACE collectively consolidated five VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (see Consolidated Variable Interest Entities below). As of December 31, 2018 and 2017, Exelon and Generation collectively had significant interests in seven 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).

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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, 2018 and 2017 are as follows:

	December 31, 2018			
	Exelon[(a)]	Generation	PHI[(a)]	ACE
Current assets	$938	$ 931	$ 7	4
Noncurrent assets	9,071	9,045	26	19
Total assets	$10,009	$ 9,976	$ 33	$ 23
Current liabilities	$274	$ 252	$ 22	19
Noncurrent liabilities	3,280	3,233	47	40
Total liabilities	$3,554	$ 3,485	$ 69	$ 59

	December 31, 2017			
	Exelon[(a)]	Generation	PHI[(a)]	ACE
Current assets	$662	$ 652	$ 10	$ 6
Noncurrent assets	9,317	9,286	31	23
Total assets	$9,979	$ 9,938	$ 41	$ 29
Current liabilities	$308	$ 272	$ 36	$ 32
Noncurrent liabilities	3,316	3,250	66	58
Total liabilities	$3,624	$ 3,522	$ 102	$ 90

____

(a) 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.

As of December 31, 2018 and 2017, Exelon's and Generation's consolidated VIEs consist of:

Investments in Other Energy Related Companies

During 2015, Generation sold 69% of its equity interest in a company to a tax equity investor. The company holds an equity method investment in a distributed energy company that is an unconsolidated VIE (see unconsolidated VIE section for additional details). Generation and the tax equity investor contributed a total of $227 million of equity in proportion to their ownership interests to the company. The company meets the definition of a VIE because it has a similar structure to a limited partnership and the limited partners do not have kick-out rights with respect to the general partner. Generation is the primary beneficiary because Generation manages the day-to-day activities of the entity.

During the fourth quarter of 2017 Generation acquired a controlling financial interest in an energy development company. The company is in the development stage and requires additional subordinated financial support from the equity holders to fund activities. Generation is the majority owner with a 62% equity interest and has the power to direct the activities that most significantly affect the economic performance of the company.

Renewable Energy Project Companies

In July 2017, Generation sold a 49% interest in EGRP to an outside investor for $400 million of cash plus immaterial working capital and other customary post-closing adjustments. EGRP meets the definition of a VIE because the EGRP has a similar structure to a limited partnership and the limited partners do not have kick out rights with respect to the general partner. Generation is the primary beneficiary because Generation manages the day-to-day activities of the entity; therefore, Generation will continue to consolidate EGRP. EGRP is a collection of wind and solar project entities and some of these project entities are VIEs that are consolidated by EGRP. The details relating to these VIEs are discussed below.

273

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation owns a number of limited liability companies that build, own, and operate solar and wind power facilities some of which are owned by EGRP. While Generation or EGRP owns 100% of the solar entities and 100% of the majority of the wind entities, it has been determined that certain of the solar and wind 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 these solar and wind entities that qualify as VIEs because Generation controls the design, construction, and operation of the facilities. Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance and there is limited recourse related to Generation related to certain solar and wind entities.

While Generation or EGRP owns 100% of the majority of the wind entities, four of the projects have noncontrolling equity interests of 1% held by third parties and one of the projects has noncontrolling equity interests related to its Class B Membership Interest (see additional details below). The entities with noncontrolling equity interests of 1% held by third parties meet the definition of a VIE because the entities have noncontrolling equity interest holders that absorb variability from the wind projects. Generation’s or the EGRP's current economic interests in three 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 or EGRP are 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 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. Generation is the primary beneficiary of these wind entities because Generation controls the design, construction, and operation of the facilities.

In December 2016, Generation sold 100% of the Class B Membership Interests to a tax equity investor and retained 100% of the Class A Membership Interests of its equity interest in one of its wind entities that was previously consolidated under the voting interest model and was subsequently contributed to EGRP in 2017. The wind entity 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. 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.

In 2017, Generation’s interests in EGRP were contributed to and are pledged for the ExGen Renewables IV non-recourse debt project financing structure. Refer to Note 13 — Debt and Credit Agreements for additional information on ExGen Renewables IV and ITEM 2. PROPERTIES for additional details on the specific projects included within EGRP.

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 $34 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.

CENG

CENG is a joint venture between Generation and EDF. 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 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

Table of Contents

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 results of operations and financial position of CENG.

Exelon and Generation, where indicated, provide the following support to CENG:

- under power purchase agreements with CENG, Generation purchased or will purchase 50.01% of the available output generated by the CENG nuclear plants not subject to other contractual agreements from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs were suspended during the term of the RSSA, through the end of March 31, 2017. With the expiration of the RSSA, the PPA was reinstated beginning April 1, 2017. (see Note 4 — Regulatory Matters for additional details),
- Generation provided a $400 million loan to CENG. As of December 31, 2018, the remaining obligation is $196 million, including accrued interest. The remaining balance was fully paid by CENG in January 2019.
- 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 22 — Commitments and Contingencies for more details),
- Generation and EDF share in the $688 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance, and
- Exelon has executed an agreement to provide up to $245 million to support the operations of CENG as well as a $165 million guarantee of CENG’s cash pooling agreement with its subsidiaries.

As of December 31, 2018 and 2017, Exelon's, PHI's and ACE's consolidated VIE consists of:

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, 2018, 2017 and 2016, ACE transferred $30 million, $48 million and $60 million to ATF, respectively.

As of December 31, 2018 and 2017, ComEd, PECO, BGE, Pepco and DPL do not have any material consolidated VIEs.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Assets and Liabilities of Consolidated VIEs
Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of December 31, 2018 and 2017, these assets and liabilities primarily consisted of the following:

	December 31, 2018			
	Exelon[a]	Generation	PHI[a]	ACE
Cash and cash equivalents	$414	$ 414	$ —	$ —
Restricted cash and cash equivalents	66	62	4	4
Accounts receivable, net				
Customer	146	146	—	—
Other	23	23	—	—
Inventory				
Materials and supplies	212	212	—	—
Other current assets	52	49	3	—
Total current assets	913	906	7	4
Property, plant and equipment, net	6,145	6,145	—	—
Nuclear decommissioning trust funds	2,351	2,351	—	—
Other noncurrent assets	258	232	26	19
Total noncurrent assets	8,754	8,728	26	19
Total assets	$9,667	$ 9,634	$ 33	$ 23
Long-term debt due within one year	$87	$ 66	$ 21	$ 18
Accounts payable	96	96	—	—
Accrued expenses	72	72	1	1
Unamortized energy contract liabilities	15	15	—	—
Other current liabilities	3	3	—	—
Total current liabilities	273	252	22	19
Long-term debt	1,072	1,025	47	40
Asset retirement obligations	2,160	2,160	—	—
Unamortized energy contract liabilities	1	1	—	—
Other noncurrent liabilities	42	42	—	—
Total noncurrent liabilities	3,275	3,228	47	40
Total liabilities	$3,548	$ 3,480	$ 69	$ 59

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

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	December 31, 2017			
	Exelon[(a)]	Generation	PHI[(a)]	ACE
Cash and cash equivalents	$126	$ 126	$—	$—
Restricted cash and cash equivalents	64	58	6	6
Accounts receivable, net				
Customer	170	170	—	—
Other	25	25	—	—
Inventory				
Materials and supplies	205	205	—	—
Other current assets	45	41	4	—
Total current assets	635	625	10	6
Property, plant and equipment, net	6,186	6,186	—	—
Nuclear decommissioning trust funds	2,502	2,502	—	—
Other noncurrent assets	274	243	31	23
Total noncurrent assets	8,962	8,931	31	23
Total assets	$9,597	$ 9,556	$ 41	$ 29
Long-term debt due within one year	$102	$ 67	$ 35	$ 31
Accounts payable	114	114	—	—
Accrued expenses	67	66	1	1
Unamortized energy contract liabilities	18	18	—	—
Other current liabilities	7	7	—	—
Total current liabilities	308	272	36	32
Long-term debt	1,154	1,088	66	58
Asset retirement obligations	2,035	2,035	—	—
Other noncurrent liabilities	121	121	—	—
Total noncurrent liabilities	3,310	3,244	66	58
Total liabilities	$3,618	$ 3,516	$ 102	$ 90

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

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 in 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, 2018 and 2017, Exelon and Generation had significant unconsolidated variable interests in seven VIEs for which Exelon or Generation, as applicable, was not the primary beneficiary. These interests include certain equity method investments and certain commercial agreements. Exelon and Generation only include unconsolidated VIEs that are individually material in the tables below. However, Exelon and Generation have several individually immaterial VIEs that in aggregate represent a total investment of $15 million and $13 million, respectively,

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

as of December 31, 2018. These immaterial VIEs are equity and debt securities in energy development companies. As of December 31, 2018, the maximum exposure to loss related to these securities included in Investments in Exelon's and Generation's Consolidated Balance Sheets is limited to the $15 million and $13 million, respectively.
The following tables present summary information about Exelon and Generation’s significant unconsolidated VIE entities:

December 31, 2018	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 597	$ 472	$1,069
Total liabilities[(a)]	37	222	259
Exelon's ownership interest in VIE[(a)]	—	223	223
Other ownership interests in VIE[(a)]	560	27	587
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments	—	223	223
Contract intangible asset	7	—	7
Net assets pledged for Zion Station decommissioning[(b)]	—	—	—

December 31, 2017	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 625	$ 509	$1,134
Total liabilities[(a)]	37	228	265
Exelon's ownership interest in VIE[(a)]	—	251	251
Other ownership interests in VIE[(a)]	588	30	618
Registrants’ maximum exposure to loss:			
Carrying amount of equity method investments	—	251	251
Contract intangible asset	8	—	8
Net assets pledged for Zion Station decommissioning[(b)]	2	—	2

____

(a) These items represent amounts on the unconsolidated VIE balance sheets, not in 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 in 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 $9 million and $39 million as of December 31, 2018 and December 31, 2017, respectively; offset by payables to ZionSolutions LLC of $9 million and $37 million as of December 31, 2018 and December 31, 2017, respectively. These items are included to provide information regarding the relative size of the ZionSolutions, LLC unconsolidated VIE.

For each of the unconsolidated VIEs, Exelon and Generation have assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would materially affect the fair value or risk of their variable interests in these VIEs.
As of December 31, 2018 and 2017, Exelon's and Generation's 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

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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 15 — 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 Distributed Energy Companies

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 contributed a total $85 million of equity. 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. Generation is not the primary beneficiary; therefore, the investment continues to be recorded using the equity method.

During 2015, a company that is consolidated by Generation as a VIE entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of another distributed energy company (see additional details in the Consolidated Variable Interest Entities section above). The equity holders (of which Generation is one) contributed to the distributed energy company a total of $227 million of equity in proportion to their ownership interests. The equity holders provided a parental guarantee of up to $275 million in support of equity contributions to the distributed energy company. As all equity contributions were made as of the first quarter of 2017, there is no further payment obligation under the parental guarantee. 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. Generation is not the primary beneficiary; therefore, the investment is recorded using the equity method.

Both distributed energy companies from the 2015 and 2014 arrangements are considered related parties to Generation.

ComEd and PECO

The financing trust of ComEd, ComEd Financing III, and the financing trusts of PECO, PECO Trust III and PECO Trust IV, are not consolidated in Exelon's, ComEd's, or PECO's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd and PECO have concluded that they do not have a significant variable interest in ComEd Financing III, PECO Trust III, or PECO Trust IV 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 13 — Debt and Credit Agreements for additional information.

3. Revenue from Contracts with Customers (All Registrants)

The Registrants recognize revenue from contracts with customers to depict the transfer of goods or services to customers at an amount that the entities expect to be entitled to in exchange for those goods or services. Generation's primary sources of revenue include competitive sales of power, natural gas, and other energy-related products and services. The Utility Registrants' primary sources of revenue include regulated electric and gas tariff sales, distribution and transmission services. The performance obligations associated with these sources of revenue are further discussed below.

Unless otherwise noted, for each of the significant revenue categories and related performance obligations described below, the Registrants have the right to consideration from the customer in an amount that corresponds directly with the value transferred to the customer for the performance completed to date. Therefore, the Registrant's have elected to use the right to invoice practical expedient for the contracts within these revenue categories and generally

recognize revenue in the amount for which they have the right to invoice the customer. As a result, there are generally no significant judgments used in determining or allocating the transaction price.

Competitive Power Sales (Exelon and Generation)

Generation sells power and other energy-related commodities to both wholesale and retail customers across multiple geographic regions through its customer-facing business, Constellation. Power sale contracts generally contain various performance obligations including the delivery of power and other energy-related commodities such as capacity, ZECs, RECs or other ancillary services. Certain performance obligations such as power and capacity are generally delivered over time whereas other performance obligations such as RECs and ZECs are generally delivered at a point in time. In either case, revenues related to all of the performance obligations in such bundled power sale contracts are generally recognized concurrently as the power is generated. Except as noted in the paragraph below, there are no significant judgments in allocating the transaction price since all performance obligations are satisfied simultaneously upon the generation of power. Payment terms generally require that the customers pay for the power or the energy-related commodity within the month following delivery to the customer and there are generally no significant financing components.

Certain contracts may contain limits on the total amount of revenue we are able to collect over the entire term of the contract. In such cases, the Registrants estimate the total consideration expected to be received over the term of the contract net of the constraint and allocate the expected consideration to the performance obligations in the contract such that revenue is recognized ratably over the term of the entire contract as the performance obligations are satisfied.

Competitive Natural Gas Sales (Exelon and Generation)

Generation sells natural gas on a full requirements basis or for an agreed upon volume to both commercial and residential customers. The primary performance obligation associated with natural gas sale contracts is the delivery of the natural gas to the customer. Revenues related to the sale of natural gas are recognized over time as the natural gas is delivered to and consumed by the customer. Payment from customers is typically due within the month following delivery of the natural gas to the customer and there are generally no significant financing components.

Other Competitive Products and Services (Exelon and Generation)

Generation also sells other energy-related products and services such as long-term construction and installation of energy efficiency assets and new power generating facilities, primarily to commercial and industrial customers. These contracts generally contain a single performance obligation, which is the construction and/or installation of the asset for the customer. The average contract term for these projects is approximately 18 months. Revenues, and associated costs, are recognized throughout the contract term using an input method to measure progress towards completion. The method recognizes revenue based on the various inputs used to satisfy the performance obligation, such as costs incurred and total labor hours expended. The total amount of revenue that will be recognized is based on the agreed upon contractually-stated amount. Payments from customers are typically due within 30 or 45 days from the date the invoice is generated and sent to the customer.

Regulated Electric and Gas Tariff Sales (Exelon and the Utility Registrants)

The Utility Registrants sell electricity and electricity distribution services to residential, commercial, industrial and governmental customers through regulated tariff rates approved by their state regulatory commissions. PECO, BGE and DPL also sell natural gas and gas distribution services to residential, commercial, and industrial customers through regulated tariff rates approved by their state regulatory commissions. The performance obligation associated with these tariff sale contracts is the delivery of electricity and/or natural gas. Tariff sales are generally considered daily contracts given that customers can discontinue service at any time. Revenues are generally recognized over time (each day) as the electricity and/or natural gas is delivered to customers. Payment terms generally require that customers pay for the services within the month following delivery of the electricity or natural gas to the customer and there are generally no significant financing components or variable consideration.

Electric and natural gas utility customers have the choice to purchase electricity or natural gas from competitive electric generation and natural gas suppliers. While the Utility Registrants are required under state legislation to bill their customers for the supply and distribution of electricity and/or natural gas, they recognize revenue related only to the distribution services when customers purchase their electricity or natural gas from competitive suppliers.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Regulated Transmission Services (Exelon and the Utility Registrants)
Under FERC's open access transmission policy, 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 approved by FERC. The Utility Registrants are members of PJM, the regional transmission organization designated by FERC to coordinate the movement of wholesale electricity in PJM's region, which includes portions of the mid-Atlantic and Midwest. In accordance with FERC-approved rules, the Utility Registrants and other transmission owners in the PJM region make their transmission facilities available to PJM, which directs and controls the operation of these transmission facilities and accordingly compensates the Utility Registrants and other transmission owners. The performance obligations associated with the Utility Registrants' contract with PJM include (i) Network Integration Transmission Services (NITS), (ii) scheduling, system control and dispatch services, and (iii) access to the wholesale grid. These performance obligations are satisfied over time, and Utility Registrants utilize output methods to measure the progress towards their completion. Passage of time is used for NITS and access to the wholesale grid and MWhs of energy transported over the wholesale grid is used for scheduling, system control and dispatch services. PJM pays the Utility Registrants for these services on a weekly basis and there are no financing components or variable consideration.
Costs to Obtain or Fulfill a Contract with a Customer (Exelon and Generation)
Generation incurs incremental costs in order to execute certain retail power and gas sales contracts. These costs primarily relate to retail broker fees and sales commissions. Generation has capitalized such contract acquisition costs in the amount of $32 million and $26 million as of December 31, 2018 and December 31, 2017, respectively, within Other current assets and Other deferred debits in Exelon's and Generation's Consolidated Balance Sheets. These costs are capitalized when incurred and amortized using the straight-line method over the average length of such retail contracts, which is approximately 2 years. Exelon and Generation recognized amortization expense associated with these costs in the amount of $22 million and $30 million for the twelve months ended December 31, 2018, and December 31, 2017, respectively, within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Generation does not incur material costs to fulfill contracts with customers that are not already capitalized under existing guidance. In addition, the Utility Registrants do not incur any material costs to obtain or fulfill contracts with customers.
Contract Balances (All Registrants)
Contract Assets
Generation records contract assets for the revenue recognized on the construction and installation of energy efficiency assets and new power generating facilities before Generation has an unconditional right to bill for and receive the consideration from the customer. These contract assets are subsequently reclassified to receivables when the right to payment becomes unconditional. Generation records contract assets and contract receivables within Other current assets and Accounts receivable, net - Customer, respectively, within Exelon's and Generation's Consolidated Balance Sheets. The following table provides a rollforward of the contract assets reflected in Exelon's and Generation's Consolidated Balance Sheets from January 1, 2018 to December 31, 2018:

Contract Assets	Exelon and Generation
Balance as of January 1, 2018	$ 283
Increases as a result of changes in the estimate of the stage of completion	50
Amounts reclassified to receivables	(146)
Balance at December 31, 2018	$ 187

The Utility Registrants do not have any contract assets.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Contract Liabilities

Generation records contract liabilities when consideration is received or due prior to the satisfaction of the performance obligations. These contract liabilities primarily relate to upfront consideration received or due for equipment service plans, solar panel leases and the Illinois ZEC program that introduces a cap on the total consideration to be received by Generation. The Generation contract liability related to the Illinois ZEC program includes certain amounts with ComEd that are eliminated in consolidation in Exelon's Consolidated Statements of Operations and Consolidated Balance Sheets. Generation records contract liabilities within Other current liabilities and Other noncurrent liabilities within Exelon's and Generation's Consolidated Balance Sheets. The following table provides a rollforward of the contract liabilities reflected in Exelon's and Generation's Consolidated Balance Sheet from January 1, 2018 to December 31, 2018:

Contract Liabilities	Exelon	Generation
Balance as of January 1, 2018	$ 35	$ 35
Increases as a result of additional cash received or due	179	465
Amounts recognized into revenues	(187)	(458)
Balance at December 31, 2018	$ 27	$ 42

The Utility Registrants also record contract liabilities when consideration is received prior to the satisfaction of the performance obligations. As of December 31, 2018 and December 31, 2017, the Utility Registrants' contract liabilities were immaterial.

Transaction Price Allocated to Remaining Performance Obligations (All Registrants)

The following table shows the amounts of future revenues expected to be recorded in each year for performance obligations that are unsatisfied or partially unsatisfied as of December 31, 2018. Generation has elected the exemption which permits the exclusion from this disclosure of certain variable contract consideration. As such, the majority of Generation's power and gas sales contracts are excluded from this disclosure as they contain variable volumes and/or variable pricing. Thus, this disclosure only includes contracts for which the total consideration is fixed and determinable at contract inception. The average contract term varies by customer type and commodity but ranges from one month to several years.

The majority of the Utility Registrants' tariff sale contracts are generally day-to-day contracts and, therefore, do not contain any future, unsatisfied performance obligations to be included in this disclosure. Further, the Utility Registrants have elected the exemption to not disclose the transaction price allocation to remaining performance obligations for contracts with an original expected duration of one year or less. As such, gas and electric tariff sales contracts and transmission revenue contracts are excluded from this disclosure.

	2019	2020	2021	2022	2023 and thereafter	Total
Exelon	$631	$329	$119	$47	$ 138	$1,264
Generation	631	329	119	47	138	1,264

Revenue Disaggregation (All Registrants)

The Registrants disaggregate revenue recognized from contracts with customers into categories that depict how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors. See Note 24 — Segment Information for the presentation of the Registrant's revenue disaggregation.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

4. Regulatory Matters (All Registrants)
The following matters below discuss the status of material regulatory and legislative proceedings of the Registrants.
Utility Regulatory Matters (Exelon and the Utility Registrants)
Distribution Base Rate Case Proceedings
The following tables show the completed and pending distribution base rate case proceedings in 2018.
Completed Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase (Decrease)	Approved Revenue Requirement Increase (Decrease)	Approved ROE	Approval Date	Rate Effective Date
ComEd - Illinois (Electric)[b]	April 16, 2018	$ (23)[a]	$ (24)[a]	8.69 %	December 4, 2018	January 1, 2019
PECO - Pennsylvania (Electric)[c]	March 29, 2018	$ 82[a]	$ 25[a]	N/A	December 20, 2018	January 1, 2019
BGE - Maryland (Natural Gas)	June 8, 2018 (amended August 24, 2018 and October 12, 2018)	$ 61	$ 43	9.8 %	January 4, 2019	January 4, 2019
Pepco - Maryland (Electric)	January 2, 2018 (amended February 5, 2018)	$ 3[a]	$ (15)[a]	9.5 %	May 31, 2018	June 1, 2018
Pepco - District of Columbia (Electric)[d]	December 19, 2017 (amended February 9, 2018)	$ 66	$ (24)[a]	9.525 %	August 9, 2018	August 13, 2018
DPL - Maryland (Electric)[e]	July 14, 2017 (amended November 16, 2017)	$ 19	$ 13	9.5 %	February 9, 2018	February 9, 2018
DPL - Delaware (Electric)	August 17, 2017 (amended February 9, 2018)	$ 12[a]	$ (7)[a]	9.7 %	August 21, 2018	March 17, 2018
DPL - Delaware (Natural Gas)	August 17, 2017 (amended February 9, 2018)	$ 4[a]	$ (4)[a]	9.7 %	November 8, 2018	March 17, 2018

____

(a) Includes the annual ongoing TCJA tax savings further discussed below.

(b) Pursuant to EIMA and FEJA, ComEd's electric distribution rates are established through a performance-based formula, which sunsets at the end of 2022. ComEd is required to file an annual update to its electric distribution formula rate on or before May 1st, with resulting rates effective in January of the following year. ComEd's annual electric distribution formula rate update is based on prior year actual costs and current year projected capital additions (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred from the year (annual reconciliation).

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd’s 2018 approved revenue requirement above reflects a decrease of $58 million for the initial year revenue requirement for 2018 and an increase of $34 million related to the annual reconciliation for 2017. The revenue requirement for 2018 and the annual reconciliation for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points. See table below for ComEd's regulatory assets associated with its electric distribution formula rate.

During the first quarter of 2018, ComEd revised its electric distribution formula rate to implement revenue decoupling provisions provided for under FEJA. As a result of this revision, ComEd’s electric distribution formula rate revenues are not impacted by abnormal weather, usage per customer or numbers of customers. ComEd began reflecting the impacts of this change in its Operating revenues and electric distribution formula rate regulatory asset in the first quarter of 2017.

(c) The PECO base rate case proceeding was resolved through a settlement agreement, which did not specify an approved ROE.

(d) On September 7, 2018, Pepco submitted an updated filing for an increase of $4 million to the customer base rate credit established in connection with the merger between Exelon and PHI for residential customers, representing the TCJA benefits for the period January 1, 2018 through August 12, 2018.

(e) The DPL Maryland base rate case proceeding was resolved through a settlement agreement, which did not specify an overall ROE. The settlement agreement included an ROE of 9.5% solely for purposes of calculating AFUDC and regulatory asset carrying costs.

In the second quarter of 2018, DPL discovered a rate design issue in Maryland such that the current rates were not sufficient to collect the full amount of the $13 million revenue increase agreed to by the parties in the recent settlement. On September 5, 2018, the MDPSC approved DPL’s proposed revisions to resolve the rate design issue on a prospective basis, effective September 5, 2018.

Pending Distribution Base Rate Case Proceedings

Registrant/Jurisdiction	Filing Date	Requested Revenue Requirement Increase		Requested ROE		Expected Approval Timing
ACE - New Jersey (Electric)	August 21, 2018 (amended November 19, 2018)	$ 122	(a)	10.1	%	Third quarter of 2019(b)
Pepco - Maryland (Electric)	January 15, 2019	$ 30		10.3	%	Third quarter of 2019

____

(a) Requested increase is before New Jersey sales and use tax and includes $40 million of higher depreciation expense related to its updated depreciation study and the annual ongoing TCJA tax savings further discussed below.
(b) ACE plans to put interim rates in effect on or around May 21, 2019, subject to refund, as allowed by the regulation.

Transmission Formula Rates

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 (initial year revenue requirement). 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 (annual reconciliation).

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For 2018, the following total increases/(decreases) were included in ComEd's, BGE's, Pepco's, DPL's and ACE's electric transmission formula rate filings:

Registrant	Initial Revenue Requirement (Decrease) Increase[b]	Annual Reconciliation Increase/(Decrease)	Total Revenue Requirement (Decrease) Increase	Allowed Return on Rate Base[d]	Allowed ROE[e]
ComEd[a]	$ (44)	$ 18	$ (26)	8.32 %	11.50 %
BGE[a]	10	4	26 [c]	7.61 %	10.50 %
Pepco	6	2	8	7.82 %	10.50 %
DPL	14	13	27	7.29 %	10.50 %
ACE[a]	4	(4)	—	8.02 %	10.50 %

____

(a) The time period for any formal challenges to the annual transmission formula rate update filings expired with no formal challenges submitted.

(b) The initial revenue requirement changes reflect the annual benefit of lower income tax rates effective January 1, 2018 resulting from the enactment of the TCJA of $69 million, $18 million, $13 million, $12 million and $11 million for ComEd, BGE, Pepco, DPL and ACE, respectively. They do not reflect the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. See further discussion below.

(c) The change in BGE's transmission revenue requirement includes a FERC approved dedicated facilities charge of $12 million to recover the costs of providing transmission service to specifically designated load by BGE.

(d) Represents the weighted average debt and equity return on transmission rate bases.

(e) As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO, and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%. As part of the FERC-approved settlement of the ROE complaint against BGE, Pepco, DPL and ACE, the rate of return on common equity is 10.50%, inclusive of a 50-basis-point incentive adder for being a member of a RTO.

Pending Transmission Formula Rate (Exelon and PECO). On May 1, 2017, PECO filed a request with FERC seeking approval to update its transmission rates and change the manner in which PECO's transmission rate is determined from a fixed rate to a formula rate. The formula rate will be updated annually to ensure that under this rate customers pay the actual costs of providing transmission services. The formula rate filing includes a requested increase of $22 million to PECO's annual transmission revenues and a requested rate of return on common equity of 11%, inclusive of a 50 basis point adder for being a member of a regional transmission organization. PECO requested that the new transmission rate be effective as of July 2017. On June 27, 2017, FERC issued an Order accepting the filing and suspending the proposed rates until December 1, 2017, subject to refund, and set the matter for hearing and settlement judge procedures. On May 4, 2018, the Chief Administrative Law Judge terminated settlement judge procedures and designated a new presiding judge. PECO cannot predict the outcome of this proceeding, or the transmission formula FERC may approve.

On May 11, 2018, pursuant to the transmission formula rate request discussed above, PECO made its first annual formula rate update, which included a revenue decrease of $6 million. The revenue decrease of $6 million included an approximately $20 million reduction as a result of the tax savings associated with the TCJA. The updated transmission rate was effective June 1, 2018, subject to refund.

Tax Cuts and Jobs Act

The Utility Registrants have made filings with their state regulatory commissions to pass back tax savings related to TCJA to their distribution customers, which are detailed below. The tax savings include the benefit of lower federal income tax rates and the settlement of a portion of the deferred income tax regulatory liabilities established upon the enactment of the TCJA. The ongoing annual TCJA tax savings in the table below represent the annual savings for distribution customers reflected in the initial customers rates approved after the TCJA. Subsequent annual TCJA tax savings will be approved as part of the annual update to the electric distribution formula rate for ComEd or base rate case proceedings for PECO, BGE, Pepco, DPL and ACE.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Ongoing TCJA Tax Savings			Stub Period Bill Credit from TCJA Tax Savings		
Registrant/Jurisdiction	Amount	Approval Date	Rate Effective Date	Stub Period	Approval Date	Refund Amount/Period
ComEd - Illinois (Electric)	$ 201	January 18, 2018	February 1, 2018	Not applicable		
PECO - Pennsylvania (Electric)	$ 71	December 20, 2018	January 1, 2019	January 1, 2018 - December 31, 2018	December 20, 2018	$67 / 2019 (majority in January)
PECO - Pennsylvania (Natural Gas)	$ 4	(a)	July 1, 2018	Not applicable		
BGE - Maryland (Electric)	$ 72	January 31, 2018	February 1, 2018	January 1, 2018 - January 31, 2018	To be addressed in next electric distribution base rate case	
BGE - Maryland (Natural Gas)	$ 31	January 31, 2018	February 1, 2018	January 1, 2018 - January 31, 2018	January 4, 2019	$2 / Q1 2019
Pepco - Maryland (Electric)	$ 31	May 31, 2018	June 1, 2018	January 1, 2018 - June 1, 2018	May 31, 2018	$10 / July 2018
Pepco - District of Columbia (Electric)	$ 39	August 9, 2018	August 13, 2018	January 1, 2018 - August 12, 2018	September 7, 2018	$20 / September 2018
DPL - Maryland (Electric)	$ 14	April 18, 2018	April 20, 2018	January 1, 2018 - March 31, 2018	April 18, 2018	$2 / June 2018
DPL - Delaware (Electric)	$ 19	August 21, 2018	March 17, 2018	February 1, 2018 - March 17, 2018	August 21, 2018	$3 / Q4 2018
DPL - Delaware (Natural Gas)	$ 7	November 8, 2018	March 17, 2018	February 1, 2018 - March 17, 2018	November 8, 2018	$1 / Q4 2018
ACE - New Jersey (Electric)	$ 23	August 29, 2018	September 8, 2018	January 1, 2018 - June 30, 2018	August 29, 2018	$6 / Q4 2018

(a) On May 17, 2018, the PAPUC issued an order directing Pennsylvania utility companies without an existing base rate case, including PECO's gas distribution business, to start passing back the savings from January 1, 2018 onward through a negative surcharge mechanism to be effective on July 1, 2018. Pursuant to that order, PECO filed a negative surcharge mechanism and began on July 1, 2018, to return the estimated annual 2018 tax savings above to its natural gas distribution customers.

As discussed above, ComEd's, BGE's, Pepco's, DPL's and ACE's transmission formula rates currently do not provide for the pass back or recovery of income tax-related regulatory liabilities or assets, including those established upon enactment of the TCJA. On December 13, 2016 (as amended on March 13, 2017) and on February 23, 2018 (as amended on July 9, 2018), BGE and ComEd, Pepco, DPL and ACE, respectively, each filed with FERC to revise their transmission formula rate mechanisms to provide for pass back and recovery of transmission-related income tax-related regulatory liabilities and assets, including those established upon enactment of the TCJA. See discussion

below for additional information regarding these filings.
See Note 14 - Income Taxes for additional information on Corporate Tax Reform.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Other State Regulatory Matters
Illinois Regulatory Matters
Energy Efficiency Formula Rate (Exelon and ComEd). FEJA allows ComEd to defer energy efficiency costs (except for any voltage optimization costs which are recovered through the electric distribution formula rate) as a separate regulatory asset that is 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 earns a return on the energy efficiency regulatory asset at a rate equal to its weighted average cost of capital, which is based on a year-end capital structure and calculated using the same methodology applicable to ComEd's electric distribution formula rate. Beginning January 1, 2018 through December 31, 2030, the return on equity that ComEd earns on its energy efficiency regulatory asset is subject to a maximum downward or upward adjustment of 200 basis points if ComEd's cumulative persisting annual MWh savings falls short of or exceeds specified percentage benchmarks of its annual incremental savings goal. ComEd is required to file an update to its energy efficiency formula rate on or before June 1st each year, with resulting rates effective in January of the following year. The annual update is based on projected current year energy efficiency costs, PJM capacity revenues, and the projected year-end regulatory asset balance less any related deferred income taxes (initial year revenue requirement). The update also reconciles any differences between the revenue requirement in effect for the prior year and actual costs incurred from the year (annual reconciliation). The approved energy efficiency formula rate also provides for revenue decoupling provisions similar to those in ComEd's electric distribution formula rate.
During 2018, the ICC approved the following total increases in ComEd's requested energy efficiency revenue requirement:

Filing Date	Requested Revenue Requirement Increase	Approved Revenue Requirement Increase	Approved ROE	Approval Date	Rate Effective Date
June 1, 2018	$ 39	$ 42 [(a)]	8.69 %	December 4, 2018	January 1, 2019

(a) ComEd's 2018 approved revenue requirement above reflects an increase of $41 million for the initial year revenue requirement for 2018 and 2019 and an increase of $1 million related to the annual reconciliation for 2017. The revenue requirement for 2018 and 2019 and the annual reconciliation for 2017 provides for a weighted average debt and equity return on distribution rate base of 6.52% inclusive of an allowed ROE of 8.69%, reflecting the average rate on 30-year treasury notes plus 580 basis points. See table below for ComEd's regulatory assets associated with its energy efficiency formula rate.

Maryland Regulatory Matters
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 its SOS-related costs. The Administrative Charge is comprised of five components: CWC, uncollectibles, incremental costs, return, and an administrative adjustment, which acts as a proxy for retail suppliers' costs. The Commission accepted BGE's positions on recovery of CWC and pass-through recovery of BGE's actual uncollectibles and incremental costs. The order also grants BGE a return on the SOS. The Commission ruled that the level of the administrative adjustment will be determined in BGE's next rate case. Subsequently, the MDPSC Staff and residential consumer advocate sought clarification and appealed the amount of return awarded to BGE on the SOS. The appeal currently resides with the Maryland Court of Special Appeals. BGE cannot predict the outcome of this appeal.

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and natural gas smart meters at an expected total cost of $480 million of which $200 million was funded by SGIG. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. See AMI programs in the Regulatory Assets and Liabilities section below for additional information.

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-

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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 3rd order contained several cost disallowances and adjustments including disallowances of certain program and meter installation costs and denial of recovery of any return on unrecovered costs for non-AMI meters replaced under the program. BGE and the residential consumer advocate subsequently both filed a petition for rehearing of the June 3rd 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.

As a combined result of the MDPSC orders in BGE's 2015 electric and natural gas distribution base rate case, BGE recorded a $52 million charge in June 2016 to Operating and maintenance expense in Exelon's and BGE's Consolidated Statements of Operations and Comprehensive Income reducing certain regulatory assets and other long-lived assets and reclassified $56 million of legacy meter costs from Property, plant and equipment, net to Regulatory assets in Exelon's and BGE's Consolidated Balance Sheets. In BGE's 2018 natural gas distribution base rate case, the MDPSC allowed BGE to recover the gas portion of the post-test year regulatory asset, including a return thereon, over three years. The electric portion of the same regulatory asset will be addressed in BGE's next electric distribution base rate case.

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In 2013, legislation in Maryland was signed into law to establish 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 a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution base rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation.

On December 1, 2017 (as amended on January 22, 2018), BGE filed an application with the MDPSC seeking approval for a new gas infrastructure replacement plan and associated surcharge, effective for the five-year period from 2019 through 2023. On May 30, 2018, the MDPSC approved with modifications a new infrastructure plan and associated surcharge, subject to BGE's acceptance of the Order. On June 1, 2018, BGE accepted the MDPSC Order and the associated surcharge will be effective in rates beginning in January 2019. The new five-year plan calls for capital expenditures over the 2019-2023 timeframe of $732 million, with an associated revenue requirement of $200 million.

District of Columbia Regulatory Matters

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

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

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

In accordance with the Infrastructure Improvement Financing Act, Pepco filed an application for approval of the first two-year plan in the DC PLUG initiative (the First Biennial Plan) on July 3, 2017. Pepco will then be required to make two additional applications. On November 9, 2017, the DCPSC issued an order approving the First Biennial Plan and the application for a financing order. Pursuant to that order, Pepco is obligated to pay $187.5 million to the District of Columbia over the six-year project term, of which it expects to pay $30 million in 2019. Pepco recorded

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

an obligation and offsetting regulatory asset in November. Rates for the DC PLUG initiative went into effect on February 7, 2018.

New Jersey Regulatory Matters

ACE Infrastructure Investment Program Filing (Exelon, PHI and ACE). On February 28, 2018, ACE filed with the NJBPU the company's Infrastructure Investment Program (IIP) proposing to seek recovery of a series of investments through a new rider mechanism, totaling $338 million, between 2019-2022 to provide safe and reliable service for its customers. The IIP will allow for more timely recovery of investments made to modernize and enhance ACE's electric system. ACE currently expects a decision in this matter in the second quarter of 2019 but cannot predict if the NJBPU will approve the application as filed.

New Jersey Consolidated Tax Adjustment (Exelon, PHI and ACE). The Consolidated Tax Adjustment (CTA) is a ratemaking policy that requires utilities that are part of a consolidated tax group to share with customers the tax benefits that came from losses at unregulated affiliates through a reduction in rate base. After opening a generic proceeding to review the policy, in 2014, the NJBPU issued a decision which retained the CTA, but in a modified format that significantly reduced the impact of the CTA to ACE. On September 18, 2017, the Appellate Division of the Superior Court of New Jersey reversed the NJBPU's decision in adopting the revised CTA policy and held that NJBPU's actions related to the CTA constituted a rulemaking that should have been undertaken pursuant to the requirements of the Administrative Procedures Act. The Court did not address the merits of the CTA methodology itself. The NJBPU issued a proposed rule for comment, consistent with the requirements of the Administrative Procedures Act. On January 17, 2019, the NJBPU adopted the proposed CTA regulations, which do not have a material impact on ACE. The CTA regulations will be sent to the Office of Administrative Law for publication in the New Jersey Register, which is expected on or before March 4, 2019.

New Jersey Clean Energy Legislation (Exelon and ACE). On May 23, 2018, the Governor of New Jersey signed new legislation, effective immediately, that established and modified New Jersey's clean energy and energy efficiency programs and solar and renewable energy portfolio standards. The new legislation expands the state's renewable portfolio standard to require that 50% of electric generation sold be from renewable energy sources by 2030; modifies the New Jersey solar renewable energy portfolio standard to require that 5.1% of electric generation sold in New Jersey be from solar electric power by 2021; lowers the solar alternative compliance payment amount starting in 2019 and requires the NJBPU to adopt rules to replace the current solar renewable energy credit program; and requires the NJBPU to increase its offshore wind energy credit program to 3,500 MW. The new legislation further imposes an energy efficiency standard that each electric public utility will be required to reduce annual usage by 2% and provides for utilities to annually file for recovery of the costs of the programs, including the revenue impact of sales losses resulting from the programs. The NJBPU is required to initiate a study to determine the savings targets for each public utility, to adopt other rules regarding the programs, and to approve energy efficiency and peak demand reduction programs for each utility. The new legislation also requires the NJBPU to conduct an energy storage analysis including the potential costs and benefits and to initiate a proceeding to establish a goal of achieving 2,000 MW of energy storage by 2030; requires the utilities to conduct a study on voltage optimization on their distribution system; and requires the NJBPU to establish a community solar program to permit customers to participate in a solar project that is not located on the customer's property which the NJBPU issued regulations on January 17, 2019.

On the same day, the Governor of New Jersey also signed new legislation, effective immediately, that will establish a ZEC program providing compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Electric distribution utilities in New Jersey, including ACE, will be authorized to collect from retail distribution customers through a non-bypassable charge all costs associated with the utility's procurement of the ZECs. See Generation Regulatory Matters below for additional information.

Other Federal Regulatory Matters

Transmission-Related Income Tax Regulatory Assets (Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE). On December 13, 2016 (as amended on March 13, 2017), BGE filed with FERC to begin recovering certain existing and future transmission-related income tax regulatory assets through its transmission formula rate. BGE's existing regulatory assets included (1) amounts that, if BGE's transmission formula rate provided for recovery, would have been previously amortized and (2) amounts that would be amortized and recovered prospectively. ComEd, Pepco, DPL and ACE had similar transmission-related income tax regulatory liabilities and assets also requiring FERC

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

approval. On November 16, 2017, FERC issued an order rejecting BGE’s proposed revisions to its transmission formula rate to recover these transmission-related income tax regulatory assets. FERC’s rejection order focused on the lack of timeliness of BGE’s request to recover amounts that would have been previously amortized but indicated that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement. Based on FERC’s order, management of each company concluded that the portion of the total transmission-related income tax regulatory assets that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery was no longer probable of recovery. As a result, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE recorded the following charges to Income tax expense within their Consolidated Statements of Operations and Comprehensive Income in the fourth quarter of 2017, reducing their associated transmission-related income tax regulatory assets. Similar regulatory assets and liabilities at PECO are not subject to the same FERC transmission rate recovery formula and, thus, are not impacted by BGE’s November 16, 2017 FERC order. See above for additional information regarding PECO's transmission formula rate filing.

	For the year ended December 31, 2017
Exelon	$ 35
ComEd	3
BGE	5
PHI	27
Pepco	14
DPL	6
ACE	7

On December 18, 2017, BGE filed for clarification and rehearing of FERC’s order, still seeking full recovery of its existing transmission-related income tax regulatory asset amounts, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. On February 27, 2018 (and updated on March 26, 2018), BGE submitted a letter to FERC advising that the lower federal corporate income tax rate effective January 1, 2018 provided for in the TCJA will be reflected in BGE’s annual formula rate update effective June 1, 2018, but that the deferred income tax benefits will not be passed back to customers unless BGE’s formula rate is revised to provide for pass back and recovery of transmission-related income tax-related regulatory liabilities and assets.

On February 23, 2018 (as amended on July 9, 2018), ComEd, Pepco, DPL, and ACE each filed with FERC to revise their transmission formula rate mechanisms to facilitate passing back to customers ongoing annual TCJA tax savings and to permit recovery of transmission-related income tax regulatory assets, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. On September 7, 2018, FERC issued orders rejecting BGE’s December 18, 2017 request for rehearing and clarification and ComEd's, Pepco's, DPL's and ACE's February 23, 2018 (as amended on July 9, 2018) filings, again citing the lack of timeliness of the requests to recover amounts that would have been previously amortized, but indicating that ongoing recovery of certain transmission-related income tax regulatory assets would provide for a more accurate revenue requirement. The orders did not address the remittance of TCJA transmission-related income tax regulatory liabilities, but rather referenced FERC’s separate Notice of Inquiry of such amounts issued on March 15, 2018.

On October 1, 2018, ComEd, BGE, Pepco, DPL, and ACE submitted new filings to recover ongoing non-TCJA amortization amounts and refund TCJA transmission-related income tax regulatory liabilities for the prospective period starting on October 1, 2018. FERC issued deficiency letters requesting additional information on November 21, 2018 and January 28, 2019. ComEd, BGE, Pepco, DPL, and ACE responded to the November 21, 2018 deficiency letter on November 29, 2018 but cannot predict the outcome of these FERC proceedings. If FERC ultimately rules that the future, ongoing non-TCJA amortization amounts are not recoverable, Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE would record additional charges to Income tax expense, which could be up to approximately $76 million, $51 million, $15 million, $10 million, $3 million, $5 million and $2 million, respectively, as of December 31, 2018.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

On October 9, 2018, ComEd, Pepco, DPL, and ACE sought rehearing of FERC's September 7, 2018 order, still seeking full recovery of their existing transmission-related income tax regulatory asset amounts, including those amounts that would have been previously amortized and recovered through rates had the transmission formula rate provided for such recovery. ComEd, Pepco, DPL, and ACE cannot predict the outcome of this rehearing request. On November 2, 2018, BGE filed an appeal of FERC’s September 7, 2018 order to the Court of Appeals for the D.C. Circuit.

PJM Transmission Rate Design (All Registrants). On June 15, 2016, several parties, including the Utility Registrants, filed a proposed settlement with FERC to resolve outstanding issues related to cost responsibility for charges to transmission customers for certain transmission facilities that operate at or above 500 kV. The settlement included provisions for monthly credits or charges related to the periods prior to January 1, 2016 that are expected to be refunded or recovered through PJM wholesale transmission rates through December 2025.

On May 31, 2018, FERC issued an order approving the settlement and directed PJM to adjust wholesale transmission rates within 30 days. Pursuant to the order, similar charges for the period January 1, 2016 through June 30, 2018 will also be refunded or recovered through PJM wholesale transmission rates over the subsequent 12-month period. PJM commenced billing the refunds and charges associated with this settlement in August 2018. The Utility Registrants expect to refund or recover these settlement amounts through prospective electric distribution customer rates. On July 2, 2018, several parties filed petitions for rehearing or clarification.

Pursuant to the FERC approval of the settlement and the expected refund or recovery of the associated amounts from electric distribution customers, in the second quarter of 2018 and as adjusted in the third quarter of 2018, the Utility Registrants recorded the following payables to/receivables from PJM and related regulatory assets/liabilities. Generation recorded a $41 million net payable to PJM and a pre-tax charge within Purchased power and fuel expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

	PJM Receivable	PJM Payable	Regulatory Asset	Regulatory Liability
Exelon	$ 220	$ 176	$ 136	$ 221
Generation[(a)]	—	41	—	—
ComEd	122	—	—	122
PECO	85	—	—	85
BGE	—	51	51	—
PHI	13	84	85	14
Pepco	—	84	84	—
DPL	10	—	—	10
ACE	3	—	1	4

(a) Does not include an offsetting receivable from New Jersey Utilities of $16 million as of December 31, 2018.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Regulatory Assets and Liabilities
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.
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, 2018 and December 31, 2017:

December 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits	$2,553	$—	$—	$—	$—	$—	$—	$—
Pension and other postretirement benefits - Merger related	1,266	—	—	—	—	—	—	—
Deferred income taxes	414	—	404	—	10	10	—	—
AMI programs - Deployment Costs	202	—	—	113	89	50	39	—
AMI programs - Legacy Meters	328	136	24	48	120	90	30	—
AMI programs - Post-test year costs	32	—	—	32	—	—	—	—
Electric distribution formula rate annual reconciliations	158	158	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	81	81	—	—	—	—	—	—
Energy efficiency costs	472	472	—	—	—	—	—	—
Fair value of long-term debt	702	—	—	—	569	—	—	—
Fair value of PHI's unamortized energy contracts	561	—	—	—	561	—	—	—
Asset retirement obligations	118	79	22	16	1	1	—	—
MGP remediation costs	326	309	17	—	—	—	—	—
Renewable energy	249	249	—	—	—	—	—	—
Electric Energy and Natural Gas Costs	193	—	49	51	93	84	—	9
Transmission formula rate annual reconciliations	41	6	—	4	31	10	14	7
Energy efficiency and demand response programs	545	—	1	289	255	188	67	—
Merger integration costs	42	—	—	3	39	18	11	10
Under-recovered revenue decoupling	59	—	—	2	57	57	—	—
Securitized stranded costs	50	—	—	—	50	—	—	50
Removal costs	564	—	—	—	564	158	97	309
DC PLUG charge	159	—	—	—	159	159	—	—
Deferred storm costs	41	—	—	—	41	9	4	28
Other	303	110	24	17	162	79	28	13
Total regulatory assets	9,459	1,600	541	575	2,801	913	290	426
Less: current portion	1,222	293	81	177	489	270	59	40
Total noncurrent regulatory assets	$8,237	$1,307	$460	$398	$2,312	$643	$231	$386

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2018	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Deferred income taxes	$5,228	$2,394	$—	$1,132	$1,702	$798	$510	$394
Nuclear decommissioning	2,606	2,217	389	—	—	—	—	—
Removal costs	1,547	1,368	—	52	127	20	107	—
Electric Energy and Natural Gas Costs	294	137	132	6	19	—	18	1
Other	528	227	75	79	100	11	30	25
Total regulatory liabilities	10,203	6,343	596	1,269	1,948	829	665	420
Less: current portion	644	293	175	77	84	7	59	18
Total noncurrent regulatory liabilities	$9,559	$6,050	$421	$1,192	$1,864	$822	$606	$402

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory assets								
Pension and other postretirement benefits	$2,455	$—	$—	$—	$—	$—	$—	$—
Pension and other postretirement benefits - Merger related	1,393	—	—	—	—	—	—	—
Deferred income taxes	306	—	297	—	9	9	—	—
AMI programs - Deployment costs	385	—	—	129	101	58	43	—
AMI programs - Legacy meters	223	155	36	53	134	100	34	—
AMI programs - Post-test year costs	32	—	—	32	—	—	—	—
Electric distribution formula rate annual reconciliations	186	186	—	—	—	—	—	—
Electric distribution formula rate significant one-time events	58	58	—	—	—	—	—	—
Energy efficiency costs	166	166	—	—	—	—	—	—
Fair value of long-term debt	758	—	—	—	619	—	—	—
Fair value of PHI's unamortized energy contracts	750	—	—	—	750	—	—	—
Asset retirement obligations	109	73	22	14	—	—	—	—
MGP remediation costs	295	273	22	—	—	—	—	—
Renewable energy	258	256	—	—	2	—	1	1
Electric energy and natural gas costs	47	—	1	16	30	8	7	15
Transmission formula rate annual reconciliations	35	6	—	7	22	3	8	11
Energy efficiency and demand response programs	596	—	1	285	310	229	81	—
Merger integration costs	45	—	—	6	39	20	10	9
Under-recovered revenue decoupling	55	—	—	14	41	38	3	—
Securitized stranded costs	79	—	—	—	79	—	—	79
Removal costs	529	—	—	—	529	150	93	286
DC PLUG charge	190	—	—	—	190	190	—	—
Deferred storm costs	27	—	—	—	27	7	5	15
Other	311	106	31	15	165	79	29	14
Total regulatory assets	9,288	1,279	410	571	3,047	891	314	430
Less: current portion	1,267	225	29	174	554	213	69	71
Total noncurrent regulatory assets	$8,021	$1,054	$381	$397	$2,493	$678	$245	$359

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2017	Exelon	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Regulatory liabilities								
Deferred income taxes	$5,241	$2,479	$ —	$1,032	$1,730	$ 809	$510	$411
Nuclear decommissioning	3,064	2,528	536	—	—	—	—	—
Removal costs	1,573	1,338	—	105	130	20	110	—
Electric Energy and Natural Gas Costs	111	47	60	—	4	—	1	3
Other	399	185	94	26	64	3	14	8
Total regulatory liabilities	10,388	6,577	690	1,163	1,928	832	635	422
Less: current portion	523	249	141	62	56	3	42	11
Total noncurrent regulatory liabilities	$9,865	$6,328	$ 549	$1,101	$1,872	$ 829	$593	$411

Descriptions of the regulatory assets and liabilities included in the tables above are summarized below, including their recovery and amortization periods.

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Pension and Other Postretirement Benefits	Primarily reflects the Utility Registrants' portion of deferred costs, including unamortized actuarial losses (gains) and prior service costs (credits), associated with Exelon's pension and other postretirement benefit plans, which are recovered through customer rates once amortized through net periodic benefit cost. Also, includes the Utility Registrants' non–service cost components capitalized in Property, plant and equipment, net on their Consolidated Balance Sheets.	The deferred costs are amortized over the plan participants' average remaining service periods subject to applicable pension and other postretirement cost recognition policies. See Note 16 – Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	No
Pension and Other Postretirement Benefits - Merger Related	The deferred costs are amortized over the plan participants' average remaining service periods subject to applicable pension and other postretirement cost recognition policies. See Note 16 – Retirement Benefits for additional information. The capitalized non–service cost components are amortized over the lives of the underlying assets.	Legacy Constellation - 2038 Legacy PHI - 2032	No

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Deferred Income Taxes	Deferred income taxes that are recoverable or refundable through customer rates, primarily associated with accelerated depreciation, the equity component of AFUDC, and the effects of income tax rate changes, including those resulting from the TCJA. These amounts include transmission-related regulatory liabilities that require FERC approval separate from the transmission formula rate. See Transmission-Related Income Tax Regulatory Assets section above for additional information.	Over the period in which the related deferred income taxes reverse, which is generally based on the expected life of the underlying assets. For TCJA, generally refunded over the remaining depreciable life of the underlying assets, except in certain jurisdictions where the commissions have approved a shorter refund period for certain assets not subject to IRS normalization rules.	No
AMI Programs - Deployment Costs	Installation costs of new smart meters, including implementation costs at Pepco and DPL of dynamic pricing for energy usage resulting from smart meters.	BGE - 2026 Pepco - 2027 DPL - 2030	Yes
AMI Programs - Legacy Meters	Early retirement costs of legacy meters.	ComEd - 2028 PECO - 2020 BGE - 2028 Pepco - 2027 DPL - 2030	ComEd, Pepco (District of Columbia), DPL (Delaware) - Yes PECO, BGE, Pepco (Maryland), DPL (Maryland) - No
AMI Programs - Post-test year incremental costs	Post-test year incremental program deployment costs of smart meters. As of December 31, 2018 and 2017, the portion of BGE's regulatory asset related to gas and electric costs was $10 million and $22 million, respectively.	BGE (gas) - 2021 BGE (electric) - Not currently being recovered.	BGE (gas) - Yes BGE (electric) - No
Electric distribution formula rate annual reconciliations	Under-recoveries related to electric distribution service costs recoverable through ComEd's performance-based formula rate, which is updated annually with rates effective on January 1st.	2020	Yes
Electric distribution	Under-recoveries of electric distribution service costs related to significant one-time	2022	Yes

formula rate significant one-time events	events (e.g., storm costs), which are recovered over 5 years from date of the event.

296

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Energy Efficiency Costs	Costs recovered through the energy efficiency formula rate tariff and the reconciliation of the difference of the revenue requirement in effect for the prior year and the revenue requirement based on actual prior year costs. Deferred energy efficiency costs are recovered over the weighted average useful life of the related energy measure.	2029	Yes
Fair Value of Long-Term Debt	Represents the difference between the carrying value and fair value of long-term debt of PHI and BGE of $569 million and $133 million, respectively, as of December 30, 2018 and $619 million and $139 million, respectively, as of December 30, 2017, as of the PHI and Constellation merger dates.	BGE - 2043 PHI - 2045	No
Fair Value of PHI’s Unamortized Energy Contracts	Represents the regulatory assets recorded at Exelon and PHI offsetting the fair value adjustment 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.	2036	No
Asset Retirement Obligations	Future legally required removal costs associated with existing asset retirement obligations.	Over the life of the related assets.	Yes, once the removal activities have been performed.
MGP Remediation Costs	Environmental remediation costs for MGP sites.	Over the expected remediation period. See Note 22 - Commitments and Contingencies for additional information.	ComEd, PECO - No
Renewable Energy	Represents the change in fair value of ComEd‘s 20-year floating-to-fixed long-term renewable energy swap contracts.	2032	No
Electric Energy and Natural Gas Costs	Under (over) recoveries related to energy and gas supply related costs recoverable (refundable) under approved rate riders.	2025	DPL (Delaware), ACE - Yes ComEd, PECO, BGE, Pepco, DPL (Maryland) - No
Transmission formula rate annual reconciliations	Under (over)-recoveries related to transmission service costs recoverable through the Utility Registrants’ FERC formula rates, which are updated annually with rates effective each June 1st.	2020	Yes

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Line Item	Description	End Date of Remaining Recovery/Refund Period	Return
Energy efficiency and demand response programs	Includes under (over)-recoveries of costs incurred related to energy efficiency programs and demand response programs and recoverable costs associated with customer direct load control and energy efficiency and conservation programs that are being recovered from customers.	PECO - 2021 BGE - 2023 Pepco, DPL - 2033	BGE, Pepco, DPL, ACE - Yes PECO - Yes on capital investment recovered through this mechanism
Merger Integration Costs	Integration costs to achieve distribution synergies related to the Constellation merger and PHI acquisition. Costs for Pepco (Maryland) and Pepco (District of Columbia) were $9 million each as of December 31, 2018 and $11 million and $9 million, respectively, as of December 31, 2017.	BGE - 2021 Pepco - 2021 DPL- 2023 ACE - Not currently being recovered.	BGE, Pepco (Maryland), DPL - Yes Pepco (District of Columbia), ACE - No
Under (Over)-Recovered Revenue Decoupling	Electric and / or gas distribution costs recoverable from or (refundable) to customers under decoupling mechanisms.	BGE, Pepco and DPL - 2019	BGE, Pepco, DPL- No
Securitized Stranded Costs	Represents certain stranded costs associated with ACE's former electricity generation business.	2022	Yes
Removal Costs	For PHI, Pepco, DPL and ACE, the regulatory asset represents costs incurred to remove property, plant and equipment in excess of amounts received from customers through depreciation rates. For ComEd, BGE, PHI, Pepco and DPL, the regulatory liability represents amounts received from customers through depreciation rates to cover the future non–legally required cost to remove property, plant and equipment, which reduces rate base for ratemaking purposes.	PHI, Pepco, DPL and ACE - Asset is generally recovered over the life of the underlining assets. ComEd, BGE, PHI, Pepco and DPL - The liability is reduced as costs are incurred.	Yes
DC PLUG Charge	Costs associated with the DC Plug Initiative. See District of Columbia Regulatory Matters discussion above.	2019 - $30M $127 million to be determined based on future biennial plans filed with the DCPSC.	Portion of asset funded by Pepco-Yes
Deferred Storm Costs	For Pepco, DPL and ACE amounts represent total incremental storm restoration costs incurred due to major storm events recoverable from customers in the Maryland and New Jersey jurisdictions.	Pepco - 2022 DPL - 2023 ACE - 2020	Pepco, DPL - Yes ACE - No

Nuclear Decommissioning	Estimated future decommissioning costs for the Regulatory Agreement Units that are less than the associated NDT fund assets. See Note 15 - Asset Retirement Obligations for additional information	Not currently being refunded.	No

298

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Capitalized Ratemaking Amounts Not Recognized

The following table presents authorized amounts capitalized for ratemaking purposes related to earnings on shareholders' investment that are not recognized for financial reporting purposes in Exelon's and the Utility Registrant's Consolidated Balance Sheets. These amounts will be recognized as revenues in the related Consolidated Statements of Operations and Comprehensive Income in the periods they are billable to our customers.

	Exelon	ComEd[a]	PECO	BGE[b]	PHI	Pepco[c]	DPL[c]	ACE
December 31, 2018	$ 65	$ 8	$ —	$ 49	$ 8	$ 5	$ 3	$ —
December 31, 2017	$ 69	$ 6	$ —	$ 53	$ 10	$ 6	$ 4	$ —

(a) Reflects ComEd's unrecognized equity returns earned for ratemaking purposes on its electric distribution formula rate regulatory assets.

(b) BGE's authorized amounts capitalized for ratemaking purposes primarily relate to earnings on shareholders' investment on its AMI programs.

(c) Pepco's and DPL's authorized amounts capitalized for ratemaking purposes relate to earnings on shareholders' investment on their respective AMI Programs and Energy Efficiency and Demand Response Programs. The earnings on energy efficiency are on Pepco DC and DPL DE programs only.

Generation Regulatory Matters (Exelon and Generation)

Illinois Regulatory Matters

Zero Emission Standard. Pursuant to FEJA, on January 25, 2018, the ICC announced that Generation's Clinton Unit 1, Quad Cities Unit 1 and Quad Cities Unit 2 nuclear plants were selected as the winning bidders through the IPA's ZEC procurement event.

Generation executed the required ZEC procurement contracts with Illinois utilities, including ComEd, effective January 26, 2018 and began recognizing revenue, with compensation for the sale of ZECs retroactive to the June 1, 2017 effective date of FEJA. The ZEC price was initially established at $16.50 per MWh of production, subject to annual future adjustments determined by the IPA for specified escalation and pricing adjustment mechanisms designed to lower the ZEC price based on increases in underlying energy and capacity prices. Illinois utilities are required to purchase all ZECs delivered by the zero-emissions nuclear-powered generating facilities, subject to annual cost caps. For the initial delivery year, June 1, 2017 to May 31, 2018, and subsequent delivery year, June 1, 2018 to May 31, 2019, the ZEC annual cost cap was set at $235 million (ComEd's share is approximately $170 million). For subsequent delivery years, the IPA-approved targeted ZEC procurement amounts will change based on forward energy and capacity prices. ZECs delivered to Illinois utilities in excess of the annual cost cap may be paid in subsequent years if the payments do not exceed the prescribed annual cost cap for that year. For the year ended December 31, 2018, Generation recognized revenue of $373 million, of which $150 million related to ZECs generated from June 1, 2017 through December 31, 2017.

On February 14, 2017, two lawsuits were filed in the Northern District of Illinois against the IPA alleging that the state's ZEC program violates certain provisions of the U.S. Constitution. Both lawsuits argued that the Illinois ZEC program would distort PJM's FERC-approved energy and capacity market auction system of setting wholesale prices and sought a permanent injunction preventing the implementation of the program. Exelon intervened and filed motions to dismiss in both lawsuits, which were granted by the district court. On September 13, 2018, the U.S. Circuit Court of Appeals for the Seventh Circuit affirmed the lower court's dismissal of both lawsuits. The U.S. Circuit Court of Appeals for the Seventh Circuit panel denied the plaintiffs' request for rehearing on October 9, 2018. On January 7, 2019, plaintiffs filed a petition seeking Supreme Court review of the case.

New Jersey Regulatory Matters

New Jersey Clean Energy Legislation. On May 23, 2018, the Governor of New Jersey signed new legislation, effective immediately, that will establish a ZEC program providing compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. Under the legislation, the NJBPU will issue ZECs to qualifying nuclear power plants and the electric distribution utilities in New Jersey, including ACE,

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

will be required to purchase those ZECs. Selected nuclear plants will receive annual ZEC payments for each energy year (12-month period from June 1 through May 31) within 90 days after the completion of such energy year. The quantity of ZECs issued will be determined based on the greater of 40% of the total number of MWh of electricity distributed by the public electric distribution utilities in New Jersey in the prior year, or the total number of MWh of electricity generated in the prior year by the selected nuclear power plants. The ZEC price is approximately $10 per MWh during the first 3-year eligibility period. For eligibility periods following the first 3-year eligibility period, the NJBPU has discretion to reduce the ZEC price. On November 19, 2018, the NJBPU issued an order providing for the method and application process for determining the eligibility of nuclear power plants, a draft method and process for ranking and selecting eligible nuclear power plants, and the establishment of a mechanism for each regulated utility to purchase ZECs from selected nuclear power plants. On December 19, 2018, PSEG filed complete applications seeking NJBPU approval for Salem 1 and Salem 2, of which Generation owns a 42.59% ownership interest, to participate in the ZEC program. On the same day, Generation filed certain Supplemental Information with the NJBPU providing proprietary information that was requested in the application but which could not be shared with PSEG. The NJBPU must complete its processes for determining eligibility for, and participation in, the ZEC program by April 18, 2019. See Note 8 - Early Plant Retirements for additional information on New Jersey's ZEC program potential impacts to PSEG's Salem nuclear plant.

New York Regulatory Matters

New York Clean Energy Standard. On August 1, 2016, the NYPSC issued an order establishing the New York CES, a component of which included a Tier 3 ZEC program targeted at preserving the environmental attributes of zero-emissions nuclear-powered generating facilities that met specific criteria demonstrating public necessity, determined by the NYPSC to be Generation's FitzPatrick, Ginna and Nine Mile Point nuclear facilities. The New York State Energy Research and Development Authority (NYSERDA) centrally procures the ZECs through a 12-year contract extending from April 1, 2017 through March 31, 2029, administered in six two-year tranches. ZEC payments are made based upon the number of MWh produced by each facility, subject to specified caps and minimum performance requirements. The ZEC price for the first tranche was set at $17.48 per MWh of production and is 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 increases in underlying energy and capacity prices. Following the first tranche, the price will be updated bi-annually. Each Load Serving Entity (LSE) is required to purchase an amount of ZECs from NYSERDA equivalent to its load ratio share of the total electric energy in the New York Control Area. Cost recovery from ratepayers is incorporated into the commodity charges on customer bills.

Generation is currently recognizing revenue for the sale of New York ZECs in the month they are generated and for the years ended December 31, 2018 and 2017, Generation has recognized revenue of $438 million and $311 million, respectively.

On October 19, 2016, a coalition of fossil-generation companies filed a complaint in federal district court against the NYPSC alleging that the ZEC program violates certain provisions of the U.S. Constitution; specifically, that the ZEC program interferes with FERC's jurisdiction over wholesale rates and that it discriminates against out of state competitors. On December 9, 2016, several parties filed motions to intervene in the case and to dismiss the lawsuit. On July 25, 2017, the court granted the motions to dismiss. On September 27, 2018, the U.S. Court of Appeals for the Second Circuit affirmed the lower court's dismissal of the complaint against the ZEC program. On January 7, 2019, the fossil-generation companies filed a petition seeking Supreme Court review of the case.

In addition, on November 30, 2016 (as amended on January 13, 2017), a group of parties filed a Petition in New York State court seeking to invalidate the ZEC program, which argued that the NYPSC did not have authority to establish the program, that it violated state environmental law and that it violated certain technical provisions of the State Administrative Procedures Act when adopting the ZEC program. Subsequently, Generation, CENG and the NYPSC filed motions to dismiss the state court action, which were later opposed by the plaintiffs. On January 22, 2018, the court dismissed the environmental claims and the majority of the plaintiffs from the case but denied the motions to dismiss with respect to the remaining five plaintiffs and claims, without commenting on the merits of the case. Generation, CENG and the state's answers and briefs were filed on March 30, 2018. On December 17, 2018, plaintiffs filed a reply brief introducing new arguments and new evidence. The State of New York filed a motion to strike on December 28, 2018. On January 4, 2019, Generation and CENG filed a motion to strike the new arguments and new evidence. After briefing is completed, the court will decide whether or not to set the case for hearing.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Other legal challenges remain possible, the outcomes of which remain uncertain. See Note 8 - Early Plant Retirements for additional information related to Ginna and Nine Mile Point, and Note 5 - Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick.

Ginna Nuclear Power Plant Reliability Support Services Agreement. 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 RSSA to support the continued operation of Ginna to maintain the reliability of the RG&E transmission grid for a specified period of time.

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

The RSSA required Ginna to continue operating through the RSSA term. On September 30, 2016, Ginna filed the required notice with the NYPSC of its intent to continue operating beyond the March 31, 2017 expiry of the RSSA, conditioned upon successful execution of an agreement between Ginna and NYSERDA for the sale of ZECs under the New York CES. Subject to prevailing over any administrative or legal challenges, it is expected the New York CES will allow Ginna to continue to operate through the end of its current operating license in 2029. See Note 8 - Early Plant Retirements for additional information regarding the impacts of a decision to early retire a nuclear plant.

Federal Regulatory Matters

Operating License Renewals

Conowingo Hydroelectric Project. 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 (401 Certification) 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.

On April 21, 2016, Generation and the U.S. Fish and Wildlife Service of the U.S. Department of the Interior executed a Settlement Agreement resolving all fish passage issues between the parties. The financial impact of the Settlement Agreement is estimated to be $3 million to $7 million per year, on average, over the 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.

On April 27, 2018, the MDE issued its 401 Certification for Conowingo. As issued, the 401 Certification contains numerous conditions, including those relating to reduction of nutrients from upstream sources, removal of all visible trash and debris from upstream sources, and implementation of measures relating to fish passage, which could have a material, unfavorable impact on Exelon’s and Generation’s financial statements through an increase in capital expenditures and operating costs if implemented. On May 25, 2018, Generation filed complaints in federal and state court, along with a petition for reconsideration with MDE, alleging that the conditions are unfair and onerous violating MDE regulations, state, federal, and constitutional law. Generation also requested that FERC defer action on the federal license while these significant state and federal law issues are pending. On July 9, 2018, MDE filed a motion to dismiss Generation's complaint in state court, which was granted without prejudice on October 9, 2018. The court found MDE's Certification was not a "final decision" of Exelon's rights and because Exelon's motion for reconsideration remains pending, as does its administrative appeal of the 401 Certification, there was no final administrative decision for the court to review at this time. On November 5, 2018, Exelon appealed the Maryland Circuit Court's dismissal of Exelon's state complaint. Exelon continues to challenge the 401 Certification through the administrative process and in federal court. Exelon and Generation cannot predict the final outcome or its financial impact, if any, on Exelon or Generation.

As of December 31, 2018, $37 million of direct costs associated with Conowingo licensing efforts have been capitalized.

Peach Bottom Units 2 and 3. On July 10, 2018, Generation submitted a second 20-year license renewal application with the NRC for Peach Bottom Units 2 and 3. Generation anticipates the second license renewal process to take approximately 2 years from the application submission until completion of the NRC’s review process. Peach Bottom Units 2 and 3 are currently licensed to operate through 2033 and 2034, respectively.

PJM Transmission Rate Design. Refer to Other Federal Regulatory Matters above for additional information.

5. Mergers, Acquisitions and Dispositions (Exelon, Generation and PHI)

Acquisition of FirstEnergy Solutions Load Business (Exelon and Generation)

On July 9, 2018, Generation entered into an Asset Purchase Agreement (the Purchase Agreement) with FirstEnergy Solutions Corporation (FirstEnergy). Pursuant to the Purchase Agreement, FirstEnergy agreed to assign all of its retail electricity and wholesale load serving contracts and certain other related commodity contracts to Generation for an all cash purchase price of $140 million. The closing of the transaction was subject to certain conditions including the approval of the Purchase Agreement by the United States Bankruptcy Court for the Northern District of Ohio (Bankruptcy Court). At FirstEnergy's request, Bankruptcy Court's review of the transaction was delayed on six occasions, and Generation disputed these delays with the Bankruptcy Court. On January 23, 2019 the Bankruptcy Court approved an order that stipulated FirstEnergy's termination of the Purchase Agreement, effective January 22, 2019. The termination order provided for Generation to receive a refund of its escrow deposit, payment of a termination fee and reimbursement of transaction expenses, all of which were immaterial.

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

On March 31, 2017, Generation acquired the 842 MW single-unit James A. FitzPatrick (FitzPatrick) nuclear generating station located in Scriba, New York from Entergy Nuclear FitzPatrick LLC (Entergy) for a total purchase price of $289 million, which consisted of a cash purchase price of $110 million and a net cost reimbursement to and on behalf of Entergy of $179 million. As part of the acquisition agreements, Generation provided nuclear fuel and reimbursed Entergy for incremental costs to prepare for and conduct a plant refueling outage; and Generation reimbursed Entergy for incremental costs to operate and maintain the plant for the period after the refueling outage through the acquisition closing date. These reimbursements covered costs that Entergy otherwise would have avoided had it shutdown the plant as originally intended in January 2017. The amounts reimbursed by Generation were offset by FitzPatrick's electricity and capacity sales revenues for this same post-outage period. As part of the transaction, Generation received the FitzPatrick NDT fund assets and assumed the obligation to decommission FitzPatrick. The NRC license for FitzPatrick expires in 2034.

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

An after-tax bargain purchase gain of $233 million was included within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income which primarily reflects differences in strategies between Generation and Entergy for the intended use and ultimate decommissioning of the plant. See Note 15 — Asset Retirement Obligations and Note 16 — Retirement Benefits for additional information regarding the FitzPatrick decommissioning ARO and pension and OPEB updates.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the final acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for the FitzPatrick acquisition by Generation:

Cash paid for purchase price	$110
Cash paid for net cost reimbursement	125
Nuclear fuel transfer	54
Total consideration transferred	$289
Identifiable assets acquired and liabilities assumed	
Current assets	$60
Property, plant and equipment	298
Nuclear decommissioning trust funds	807
Other assets[(a)]	114
Total assets	$1,279
Current liabilities	$6
Nuclear decommissioning ARO	444
Pension and OPEB obligations	33
Deferred income taxes	149
Spent nuclear fuel obligation	110
Other liabilities	15
Total liabilities	$757
Total net identifiable assets, at fair value	$522
Bargain purchase gain (after-tax)	$233

(a) Includes a $110 million asset associated with a contractual right to reimbursement from the New York Power Authority (NYPA), a prior owner of FitzPatrick, associated with the DOE one-time fee obligation. See Note 22-Commitments and Contingencies for additional information regarding SNF obligations to the DOE.

Exelon and Generation incurred $57 million of merger and integration related costs to FitzPatrick for the year ended December 31, 2017 which are included within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Exelon and Generation did not incur any merger and integration costs related to FitzPatrick for the year ended December 31, 2018.

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.

The purchase price of $257 million 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 the acquisition date.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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), for a total purchase price consideration of approximately $7.1 billion. As a result of the merger, Merger Sub was merged into PHI (the PHI Merger) with PHI surviving as a wholly owned subsidiary of Exelon and Exelon Energy Delivery Company, LLC (EEDC), a wholly owned subsidiary of Exelon which also owns Exelon's interests in ComEd, PECO and BGE (through a special purpose subsidiary in the case of BGE). Following the completion of the PHI Merger, Exelon and PHI completed a series of internal corporate organization restructuring transactions resulting in the transfer of PHI’s unregulated business interests to Exelon and Generation and the transfer of PHI, Pepco, DPL and ACE to a special purpose subsidiary of EEDC.
Regulatory Matters
Approval of the merger in Delaware, New Jersey, Maryland and the District of Columbia was conditioned upon Exelon and PHI agreeing to certain commitments including where applicable: customer rate credits, funding for energy efficiency and delivery system modernization programs, a green sustainability fund, workforce development initiatives, charitable contributions, renewable generation and other required commitments. In addition, the orders approving the merger in Delaware, New Jersey and Maryland include a “most favored nation” provision which, generally, requires allocation of merger benefits proportionally across all the jurisdictions.
Total nominal cost of commitments was $513 million excluding renewable generation commitments (approximately $444 million on a net present value basis amount, excluding renewable generation commitments and charitable contributions).
During the fourth quarter of 2018, Exelon finalized the application of $5 million funding for residential and non-residential customers in the DPL Maryland service territory. This resulted in an adjustment to merger commitment costs recorded at Exelon Corporate and DPL. Exelon Corporate recorded a decrease of $5 million and DPL recorded an increase of $5 million in Operating and maintenance expense.
The following amounts represent total commitment costs for Exelon, PHI, Pepco, DPL and ACE that have been recorded since the merger date:

Description	Expected Payment Period	Exelon	Successor PHI	Pepco	DPL	ACE
Rate credits	2016 - 2021	$ 259	$ 264	$ 91	$ 72	$ 101
Energy efficiency	2016 - 2021	117	—	—	—	—
Charitable contributions	2016 - 2026	50	50	28	12	10
Delivery system modernization	Q2 2017	22	—	—	—	—
Green sustainability fund	Q2 2017	14	—	—	—	—
Workforce development	2016 - 2020	17	—	—	—	—
Other		29	6	1	5	—
Total commitments		$ 508	$ 320	$ 120	$ 89	$ 111
Remaining commitments as of December 31, 2018		$ 128	$ 92	$ 73	$ 12	$ 7

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

customer bill credit and the customer base rate credit commitments.
In addition, Exelon is committed to develop or to assist in the commercial development of approximately 37 MWs of new solar generation in Maryland, District of Columbia and Delaware, at an estimated cost of approximately $127 million, which will generate future earnings at Exelon and Generation. Investment costs, which are expected to be

primarily capital in nature, will be recognized as incurred and recorded on Exelon's and Generation's financial statements. As of December 31, 2018, 27 MWs were developed and Exelon and Generation have incurred costs of $83 million. Exelon has also committed to purchase 100 MWs of wind energy in PJM. DPL has committed to conducting three RFPs to procure up to a total of 120 MWs of wind RECs for the purpose of meeting Delaware's renewable portfolio standards. DPL has conducted two of the three wind REC RFPs. The first 40 MW wind REC tranche was conducted in 2017 and did not result in a purchase agreement. The second 40 MW wind REC tranche was conducted in 2018 and resulted in a proposed REC purchase agreement that is pending review and approval with the DPSC. The third and final 40 MW wind REC tranche will be conducted in 2022.

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

In July 2015, the OPC, Public Citizen, Inc., the Sierra Club and the Chesapeake Climate Action Network (CCAN) filed motions to stay the MDPSC order approving the merger. The Circuit Court judge issued an order denying the motions for stay on August 12, 2015. On January 8, 2016, the Circuit Court judge affirmed the MDPSC’s order approving the merger and denied the petitions for judicial review filed by the OPC, the Sierra Club, CCAN and Public Citizen, Inc. On January 19, 2016, the OPC filed a notice of appeal to the Maryland Court of Special Appeals, and on January 21, the Sierra Club and CCAN filed notices of appeal. On January 27, 2017, the Maryland Court of Special Appeals affirmed the Circuit Court's judgment that the MDPSC did not err in approving the merger. The OPC and Sierra Club filed petitions seeking further review in the Maryland Court of Appeals, which is the highest court in Maryland. On August 29, 2018, the Maryland Court of Appeals affirmed the MDPSC's May 2015 Order approving the merger of Exelon and PHI.

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 Legal Entity of Columbia Office of People’s Counsel, the District of Columbia Government, and Public Citizen jointly with DC Sun each filed petitions for judicial review of the DCPSC’s March 23, 2016 order with the District of Columbia Court of Appeals. On July 20, 2017, the Court issued an opinion rejecting all of appellants’ arguments and affirming the Commission’s decision approving the merger.

Accounting for the Merger Transaction

The total purchase price consideration for the PHI merger was approximately $7.1 billion. The excess of the purchase price over the estimated fair value of the assets acquired and the liabilities assumed totaled $4 billion, which was recognized as goodwill by PHI and Exelon at the merger 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. None of this goodwill is expected to be tax deductible. For purposes of future required impairment assessments, the goodwill has been assigned to PHI's reportable units Pepco, DPL and ACE. See Note 10 - Intangible Assets for additional information.

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

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.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The current impact of PHI, including its unregulated businesses, in Exelon's Consolidated Statements of Operations and Comprehensive Income includes Operating revenues and Net Income (Loss) as follows:

	For the Years Ended December 31,		
	2018	2017	2016
Operating Revenues	4,670	4,829	3,785
Net Income (Loss)	453	364	(66)

For the periods ended December 31, 2018, 2017 and 2016, the Registrants have recognized costs to achieve the PHI merger as follows:

	For the Year Ended December 31,		
Acquisition, Integration and Financing Costs[(a)]	2018	2017	2016
Exelon	$7	$16	$143
Generation	5	22	37
ComEd[(b)]	—	1	(6)
PECO	1	4	5
BGE[(b)]	1	4	(1)
Pepco[(b)]	—	(6)	28
DPL[(b)]	—	(7)	20
ACE[(b)]	—	(6)	19

	Successor			Predecessor
	For the Year Ended December 31,		March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
Acquisition, Integration and Financing Costs[(a)]	2018	2017		
PHI[(b)]	$—	$(18)	$ 69	$ 29

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

(b) For the year ended December 31, 2017, includes deferrals of previously incurred integration costs as regulatory assets of $24 million, $8 million, $8 million, and $8 million at PHI, Pepco, DPL and ACE, respectively. For the year ended December 31, 2016, includes deferrals of previously incurred integration costs as regulatory assets of $8 million, $6 million, $11 million and $4 million at ComEd, BGE, Pepco and DPL, respectively. For the Successor period March 24, 2016 to December 31, 2016, includes deferrals of previously incurred integration costs as regulatory assets of $16 million at PHI. See Note 4 - Regulatory Matters for additional information.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pro-forma Impact of the Merger

The following unaudited pro-forma financial information reflects the consolidated results of operations of Exelon as if the PHI merger 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 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 the year ended December 31, 2016.

(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.

Disposition of Oyster Creek (Exelon and Generation)

On July 31, 2018, Generation entered into an agreement with Holtec International (Holtec) and its indirect wholly owned subsidiary, Oyster Creek Environmental Protection, LLC (OCEP), for the sale and decommissioning of the Oyster Creek Generating Station (Oyster Creek) located in Forked River, New Jersey. On September 17, 2018, Oyster Creek permanently ceased generation operations.
Under the terms of the transaction, Generation will transfer to OCEP substantially all the assets associated with Oyster Creek, including assets held in NDT funds, along with the assumption of liability for all responsibility for the site, including full decommissioning and ongoing management of spent fuel until the spent fuel is moved offsite. In addition to the assumption of liability for the full decommissioning and ongoing management of spent fuel, other consideration to be received in the transaction is contingent on several factors, including a requirement that Generation deliver a minimum NDT fund balance at closing, subject to adjustment for specific terms that include income taxes that would be imposed on any net unrealized built-in gains and certain decommissioning activities to be performed during the pre-close period after the unit shuts down in the fall of 2018 and prior to the anticipated close of the transaction. The terms of the transaction also include various forms of performance assurance for the obligations of OCEP to timely complete the required decommissioning, including a parental guaranty from Holtec for all performance and payment obligations of OCEP, and a requirement for Holtec to deliver a letter of credit to Generation upon the occurrence of specified events.
As a result of the transaction, in 2018, Exelon and Generation reclassified certain Oyster Creek assets and liabilities in Exelon's and Generation's Consolidated Balance Sheets as held for sale at their respective fair values. At December 31, 2018 Generation has $897 million and $777 million of Assets held for sale and Liabilities held for sale, respectively, for Oyster Creek. Upon remeasurement of the Oyster Creek ARO in 2018, Exelon and Generation recognized an $84 million pre-tax charge to Operating and maintenance expense. See Note 15 -Asset Retirement Obligations for additional information.
Completion of the transaction contemplated by the sale agreement is subject to the satisfaction of several closing conditions, including approval of the license transfer from the NRC and other regulatory approvals, and the receipt of

a private letter ruling from the IRS. Generation currently anticipates satisfaction of the closing conditions to occur in the second half of 2019.

Disposition of EGTP and Acquisition of Handley Generating Station (Exelon and Generation)

EGTP, a Delaware limited liability company, was formed in 2014 with the purpose of financing a portfolio of assets comprised of two combined-cycle gas turbines (CCGTs) and three peaking/simple cycle facilities consisting of approximately 3.4 GW of generation capacity in ERCOT North and Houston Zones. EGTP was an indirect wholly owned subsidiary of Exelon and Generation.

EGTP’s operating cash flows were negatively impacted by certain market conditions and the seasonality of its cash flows. On May 2, 2017, as a result of the negative impacts of certain market conditions and the seasonality of its cash flows, EGTP entered into a consent agreement with its lenders to permit EGTP to draw on its revolving credit facility and initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a $460 million pre-tax impairment loss. See Note 13 - Debt and Credit Agreements for details regarding the nonrecourse debt associated with EGTP and Note 7 - Impairment of Long-Lived Assets and Intangibles for additional information.

On November 7, 2017, EGTP and all of its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware, which resulted in Exelon and Generation deconsolidating EGTP's assets and liabilities from their consolidated financial statements in the fourth quarter of 2017 that resulted in a pre-tax gain upon deconsolidation of $213 million. Concurrently with the Chapter 11 filings, Generation entered into an asset purchase agreement to acquire one of EGTP's generating plants, the Handley Generating Station, subject to a potential adjustment for fuel oil and assumption of certain liabilities. In the Chapter 11 Filings, EGTP requested that the proposed acquisition of the Handley Generating Station be consummated through a court-approved and supervised sales process. The acquisition closed on April 4, 2018 for a purchase price of $62 million. The Chapter 11 bankruptcy proceedings were finalized on April 17, 2018, resulting in the ownership of EGTP assets (other than the Handley Generating Station) being transferred to EGTP's lenders.

Other Asset Dispositions (Exelon, Generation, DPL and Pepco)

In December 2017, Generation entered into an agreement to sell its interest in an electrical contracting business that primarily installs, maintains and repairs underground and high-voltage cable transmission and distribution systems. As a result, as of December 31, 2017, certain assets and liabilities were classified as held for sale and included in the Other current assets and Other current liabilities balances in Exelon's and Generation's Consolidated Balance Sheet. On February 28, 2018, Generation completed the sale of its interest for $87 million, resulting in a pre-tax gain which is included within Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In June 2018, additional proceeds were received, and a pre-tax gain was recorded within Gain on sales of assets and businesses in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the fourth quarter of 2016, as part of its continual assessment of growth and development opportunities, Generation 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 sales of assets and businesses and pre-tax impairment charges of $23 million was recorded within Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

On June 16, 2016, Generation initiated the sales process of its Upstream business by executing a forbearance agreement with the lenders of the nonrecourse debt. See Note 13 - Debt and Credit Agreements for additional 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 and businesses in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

6. 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, 2018 and 2017:

	Average Service Life (years)	2018	2017
Asset Category			
Electric—transmission and distribution	5-90	$53,090	$49,506
Electric—generation	1-56	29,170	29,019
Gas—transportation and distribution	5-90	5,530	5,050
Common—electric and gas	5-75	1,627	1,447
Nuclear fuel [(a)]	1-8	5,957	6,420
Construction work in progress	N/A	3,377	2,825
Other property, plant and equipment [(b)]	1-50	858	999
Total property, plant and equipment		99,609	95,266
Less: accumulated depreciation [(c)]		22,902	21,064
Property, plant and equipment, net		$76,707	$74,202

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,004 million and $1,196 million at December 31, 2018 and 2017, respectively.
(b) Includes Generation’s buildings under capital lease with a net carrying value of $5 million and $7 million at December 31, 2018 and 2017, respectively. The original cost basis of the buildings was $47 million as of both December 31, 2018 and 2017, and total accumulated amortization was $42 million and $40 million, as of December 31, 2018 and 2017, respectively. Also includes ComEd’s buildings under capital lease with a net carrying value at both December 31, 2018 and 2017 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, 2018 and 2017. Includes land held for future use and non-utility property at ComEd, PECO, BGE, Pepco, DPL and ACE of $39 million, $19 million, $25 million, $61 million, $17 million and $28 million, respectively, at December 31, 2018.
(c) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,969 million and $3,159 million as of December 31, 2018 and 2017, 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	2018	2017	2016
Electric—transmission and distribution	2.73%	2.75%	2.73%
Electric—generation [(a)]	5.37%	4.36%	5.94%
Gas	2.07%	2.10%	2.17%
Common—electric and gas	6.98%	7.05%	7.41%

(a) See Note 8 — Early Plant Retirements for additional information on the accelerated net depreciation and amortization of Clinton, Quad Cities, Oyster Creek and TMI.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

	Average Service Life (years)	2018	2017
Asset Category			
Electric—generation	1-56	$29,170	$29,019
Nuclear fuel [(a)]	1-8	5,957	6,420
Construction work in progress	N/A	997	838
Other property, plant and equipment [(b)]	1-8	63	57
Total property, plant and equipment		36,187	36,334
Less: accumulated depreciation [(c)]		12,206	11,428
Property, plant and equipment, net		$23,981	$24,906

(a) Includes nuclear fuel that is in the fabrication and installation phase of $1,004 million and $1,196 million at December 31, 2018 and 2017, respectively.

(b) Includes buildings under capital lease with a net carrying value of $5 million and $7 million at December 31, 2018 and 2017, respectively. The original cost basis of the buildings was $47 million as of both December 31, 2018 and 2017, and total accumulated amortization was $42 million and $40 million, as of December 31, 2018 and 2017, respectively.

(c) Includes accumulated amortization of nuclear fuel in the reactor core of $2,969 million and $3,159 million as of December 31, 2018 and 2017, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 5.37%, 4.36% and 5.94% for the years ended December 31, 2018, 2017 and 2016, respectively. See Note 8 — Early Plant Retirements for additional information on the accelerated depreciation and amortization of Clinton, Quad Cities, Oyster Creek and TMI.

License Renewals

Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual renewal of the operating licenses for all of Generation's operating nuclear generating stations except for TMI and Clinton. As a result, the receipt of license renewals has no material impact in the Consolidated Statements of Operations and Comprehensive Income. Beginning in 2017, TMI and Oyster Creek depreciation provisions were based on their 2019 expected shutdown dates. Beginning February 2018, Oyster Creek depreciation provisions were based on its announced shutdown date of September 2018. Clinton depreciation provisions are based on an estimated useful life through 2027 which is the last year of the Illinois Zero Emissions Standard. See Note 4 — Regulatory Matters for additional information regarding license renewals and the Illinois ZECs and Note 8 — Early Plant Retirements for additional information on the impacts of expected and potential early plant retirement.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

	Average Service Life (years)	2018	2017
Asset Category			
Electric—transmission and distribution	5-80	$25,991	$24,423
Construction work in progress	N/A	705	517
Other property, plant and equipment [(a), (b)]	35-50	46	52
Total property, plant and equipment		26,742	24,992
Less: accumulated depreciation		4,684	4,269
Property, plant and equipment, net		$22,058	$20,723

(a) Includes buildings under capital lease with a net carrying value at both December 31, 2018 and 2017 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, 2018 and 2017.
(b) Represents 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 2.95%, 2.99% and 3.03% for the years ended December 31, 2018, 2017 and 2016, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

	Average Service Life (years)	2018	2017
Asset Category			
Electric—transmission and distribution	5-65	$8,359	$7,975
Gas—transportation and distribution	5-70	2,694	2,504
Common—electric and gas	5-50	756	710
Construction work in progress	N/A	343	254
Other property, plant and equipment [(a)]	50	19	21
Total property, plant and equipment		12,171	11,464
Less: accumulated depreciation		3,561	3,411
Property, plant and equipment, net		$8,610	$8,053

(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	2018	2017	2016
Electric—transmission and distribution	2.35%	2.37%	2.32%
Gas	1.90%	1.89%	1.82%
Common—electric and gas	5.44%	5.47%	5.11%

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

	Average Service Life (years)	2018	2017
Asset Category			
Electric—transmission and distribution	5-90	$7,951	$7,464
Gas—distribution	5-90	2,630	2,379
Common—electric and gas	5-40	860	771
Construction work in progress	N/A	410	367
Other property, plant and equipment [(a)]	20	25	26
Total property, plant and equipment		11,876	11,007
Less: accumulated depreciation		3,633	3,405
Property, plant and equipment, net		$8,243	$7,602

(a) Represents plant 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	2018	2017	2016
Electric—transmission and distribution	2.61%	2.58%	2.56%
Gas	2.36%	2.33%	2.45%
Common—electric and gas	8.50%	8.64%	9.45%

PHI

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

	Average Service Life (years)	2018	2017
Asset Category			
Electric—transmission and distribution	5-75	$12,664	$11,517
Gas—distribution	5-75	486	449
Common—electric and gas	5-75	126	82
Construction work in progress	N/A	912	835
Other property, plant and equipment [(a)]	3-43	99	102
Total property, plant and equipment		14,287	12,985
Less: accumulated depreciation		841	487
Property, plant and equipment, net		$13,446	$12,498

(a) Represents plant held for future use and non-utility property.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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	2018	2017	2016
Electric—transmission and distribution	2.61%	2.63%	2.52%
Gas	1.59%	2.07%	2.57%
Common—electric and gas	6.30%	6.50%	8.12%

Pepco

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

Asset Category	Average Service Life (years)	2018	2017
Electric—transmission and distribution	5-75	$9,217	$8,646
Construction work in progress	N/A	536	473
Other property, plant and equipment [(a)]	25-33	61	59
Total property, plant and equipment		9,814	9,178
Less: accumulated depreciation		3,354	3,177
Property, plant and equipment, net		$6,460	$6,001

(a) Represents plant 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 2.40%, 2.35% and 2.17% for the years ended December 31, 2018, 2017 and 2016, respectively.

DPL

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

Asset Category	Average Service Life (years)	2018	2017
Electric—transmission and distribution	5-70	$ 4,195	$ 3,875
Gas—distribution	5-75	651	614
Common—electric and gas	5-75	136	117
Construction work in progress	N/A	151	205
Other property, plant and equipment [(a)]	10-43	17	15
Total property, plant and equipment		5,150	4,826
Less: accumulated depreciation		1,329	1,247
Property, plant and equipment, net		$ 3,821	$ 3,579

(a) Represents plant held for future use and non-utility property.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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	2018	2017	2016
Electric—transmission and distribution	2.77%	2.75%	2.49%
Gas	1.59%	2.07%	2.57%
Common—electric and gas	3.70%	4.14%	4.99%

ACE

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2018 and 2017:

Asset Category	Average Service Life (years)	2018	2017
Electric—transmission and distribution	5-60	$3,866	$3,607
Construction work in progress	N/A	209	138
Other property, plant and equipment [(a)]	13-15	28	27
Total property, plant and equipment		4,103	3,772
Less: accumulated depreciation		1,137	1,066
Property, plant and equipment, net		$2,966	$2,706

____

(a) Represents plant 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 2.45%, 2.46% and 2.45% for the years ended December 31, 2018, 2017 and 2016, respectively.

Capitalized Software Costs (All Registrants)

The following tables presents net unamortized capitalized software costs and amortization of capitalized software costs by year.

Net unamortized software costs	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2018	$ 810	$ 164	$ 206	$ 98	$166	$165	$ 26	$21	$ 14
December 31, 2017	834	173	227	111	179	133	2	1	1

Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
2018	$ 282	$ 78	$ 79	$ 37	$ 48	$ 2	$ 2	$ 1
2017	270	73	73	39	46	—	—	—
2016	255	72	62	33	44	—	—	—

	Successor			Predecessor
PHI	For the year ended December 31, 2018	For the year ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
Amortization of capitalized software costs	$33	$ 34	$ 29	$ 8

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Capitalized Interest and AFUDC (All Registrants)
The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

		Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
2018	Total incurred interest[a]	$1,695	$ 464	$ 377	$ 141	$130	$ 162	$ 62	$ 68
	Capitalized interest	31	31	—	—	—	—	—	—
	Credits to AFUDC debt and equity	109	—	30	12	24	34	4	4
2017	Total incurred interest[a]	$1,658	$ 502	$ 369	$ 130	$111	$ 133	$ 54	$ 64
	Capitalized interest	63	63	—	—	—	—	—	—
	Credits to AFUDC debt and equity	108	—	20	12	22	34	10	9
2016	Total incurred interest[a]	$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

PHI	Successor			Predecessor
	For the year ended December 31, 2018	For the year ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
Total incurred interest[a]	$305	$ 263	$ 207	$ 68
Credits to AFUDC debt and equity	44	54	35	10

____

(a) Includes interest expense to affiliates.

See Note 1 — Significant Accounting Policies for additional information regarding property, plant and equipment policies. See Note 13 — Debt and Credit Agreements for additional information regarding Exelon’s, ComEd’s and PECO’s property, plant and equipment subject to mortgage liens.

7. Impairment of Long-Lived Assets and Intangibles (Exelon, Generation and PHI)

Long-Lived Assets (Exelon, Generation and PHI)

Registrants evaluate long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of 2018, updates to Exelon's long-term view of energy and capacity prices suggested that the carrying value of a group of merchant wind assets, located in West Texas, may be impaired. Upon review, the estimated undiscounted future cash flows and fair value of the group were less than its carrying value. The fair value analysis was based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. As a result, long-lived merchant wind assets held and used with a net carrying amount of $41 million were fully impaired and a pre-tax impairment charge of $41 million was recorded during 2018 within Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the first quarter of 2018, Mystic Unit 9 did not clear in the ISO-NE capacity auction for the 2021 - 2022 planning year. On March 29, 2018, Generation notified ISO-NE of the early retirement of its Mystic Generating Station's Units 7, 8, 9 and the Mystic Jet Unit (Mystic Generating Station assets) absent regulatory reforms. These events suggested that the carrying value of its New England asset group may be impaired. As a result, Generation completed a comprehensive review of the estimated undiscounted future cash flows of the New England asset group and no impairment charge was required. Further developments such as the failure of ISO-NE to adopt long-term solutions for reliability and fuel security could potentially result in future impairments of the New England asset

group, which could be material. See Note 8 — Early Plant Retirements for additional information.
In the third quarter of 2015, PHI entered into a sponsorship agreement with the District of Columbia for future sponsorship rights associated with public property within the District of Columbia and paid the District of Columbia $25 million, which Exelon and PHI had recorded as a finite-lived intangible asset as of December 31, 2016. The specific sponsorship rights were to be determined over time through future negotiations. In the fourth quarter of

2017, based upon the lack of currently available sponsorship opportunities, the asset was written off and a pre-tax impairment charge of $25 million was recorded within Operating and maintenance expense in Exelon’s and PHI’s Consolidated Statements of Operations and Comprehensive Income.

On May 2, 2017, EGTP entered into a consent agreement with its lenders to initiate an orderly sales process to sell the assets of its wholly owned subsidiaries. As a result, Exelon and Generation classified certain of EGTP's assets and liabilities as held for sale at their respective fair values less costs to sell and recorded a pre-tax impairment charge of $460 million within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income during 2017. On November 7, 2017, EGTP and its wholly owned subsidiaries filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of Delaware and, as a result, Exelon and Generation deconsolidated EGTP's assets and liabilities from their consolidated financial statements. See Note 5 — Mergers, Acquisitions and Dispositions for additional information.

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

In the first quarter of 2016, significant changes in Generation’s intended use of the Upstream oil and gas assets, developments with nonrecourse debt held by its Upstream subsidiary CEU Holdings, LLC (as described in Note 13 — Debt and Credit Agreements) and continued declines in both production volumes and commodity prices suggested that the carrying value may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of its Upstream properties were less than their carrying values. As a result, a pre-tax impairment charge of $119 million was recorded in March 2016 within Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. On June 16, 2016, Generation initiated the sales process of its Upstream natural gas and oil exploration and production business by executing a forbearance agreement with the lenders of the nonrecourse debt, see Note 13 — Debt and Credit Agreements for additional information. An additional pre-tax impairment charge of $15 million was recorded in September 2016 within Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income due to further declines in fair value. In December 2016, Generation sold substantially all of the Upstream Assets. See Note 5 — Mergers, Acquisitions and Dispositions for additional information.

The fair value analysis used in the above impairments was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue, generation and production forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon’s long-lived assets, which could be material.

Like-Kind Exchange Transaction (Exelon)

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

Pursuant to the applicable authoritative guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other-than-temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments based on the income approach, which uses a discounted cash flow analysis, taking into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

All the Headleases were terminated by the second quarter of 2016, and no events occurred prior to the termination that required Exelon to review the estimated residual values of the direct financing lease investments in 2016. On March 31, 2016, UII and MEAG finalized an agreement to terminate the MEAG Headleases, the MEAG Leases, and other related agreements prior to their expiration dates. As a result of the lease termination, UII received an early termination payment of $360 million from MEAG and wrote-off the $356 million net investment in the MEAG Headleases and the Leases. The transaction resulted in a pre-tax gain of $4 million which is reflected in Operating and maintenance expense in Exelon's Consolidated Statements of Operations and Comprehensive Income. See Note 14 — Income Taxes for additional information.

8. Early Plant Retirements (Exelon and Generation)

Exelon and Generation continuously evaluate factors that affect the current and expected economic value of Generation’s plants, including, but not limited to: market power prices, results of capacity auctions, potential legislative and regulatory solutions to ensure plants are fairly compensated for the benefits they provide through their carbon-free emissions, reliability, or fuel security, and the impact of potential rules from the EPA requiring reduction of carbon and other emissions and the efforts of states to implement those final rules. The precise timing of an early retirement date for any plant, and the resulting financial statement impacts, may be affected by many factors, including the status of potential regulatory or legislative solutions, results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and NDT fund requirements for nuclear plants, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity or other obligations, and where applicable, just prior to its next scheduled nuclear refueling outage.

Nuclear Generation

In 2015 and 2016, Generation identified the Clinton and Quad Cities nuclear plants in Illinois, Ginna and Nine Mile Point nuclear plants in New York and Three Mile Island nuclear plant in Pennsylvania as having the greatest risk of early retirement based on economic valuation and other factors.

On June 2, 2016, Generation announced it would shutdown the Clinton and Quad Cities nuclear plants on June 1, 2017 and June 1, 2018, respectively, given a lack of progress on Illinois energy legislation and MISO market reforms, and capacity auctions results that failed to cover cash operating costs and a risk-adjusted rate of return to shareholders. On December 7, 2016, Illinois FEJA was signed into law by the Governor of Illinois and included a ZES that now provides compensation to Clinton and Quad Cities for the carbon-free attributes of their production through 2027. With the passage of the Illinois ZES in December 2016, Generation reversed its June 2016 decision to permanently cease generation operations at the Clinton and Quad Cities nuclear generating plants. Clinton and Quad Cities are currently licensed to operate through 2026 and 2032, respectively. See Note 4 - Regulatory Matters for additional information on the Illinois FEJA and the ZES.

In New York, the Ginna and Nine Mile Point nuclear plants faced similar economic challenges and on August 1, 2016, the NYPSC issued an order adopting the CES, which now provides payments to Ginna and Nine Mile Point, as well as FitzPatrick, for the environmental attributes of their production through 2029. Ginna and Nine Mile Point Unit 1 are currently licensed to operate through 2029, and Nine Mile Point Unit 2 through 2046. See Note 4 - Regulatory Matters for additional information on the New York CES.

Assuming the continued effectiveness of both the Illinois ZES and the New York CES, Generation and CENG, through its ownership of Ginna and Nine Mile Point, no longer consider Clinton, Quad Cities, Ginna or Nine Mile Point to be at heightened risk for early retirement. However, to the extent either the Illinois ZES or the New York CES programs do not operate as expected over their full terms, each of these plants could again be at heightened risk for early retirement, which could have a material impact on Exelon’s and Generation’s future financial statements.

In Pennsylvania, the TMI nuclear plant failed to clear in the May 2017 PJM capacity auction for the 2020-2021 planning year, the third consecutive year that TMI failed to clear in the PJM base residual capacity auction and on May 30, 2017, based on these capacity auction results, prolonged periods of low wholesale power prices, and the

317

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

Table of Contents

absence of federal or state policies that place a value on nuclear energy for its ability to produce electricity without air pollution, Exelon announced that Generation will permanently cease generation operations at TMI on or about September 30, 2019. TMI is currently committed to operate through May 2019 and is licensed to operate through 2034. Generation has filed the required market and regulatory notifications to shutdown the plant. PJM has subsequently notified Generation that it has not identified any reliability issues and has approved the deactivation of TMI as proposed.

In 2010, Generation announced that Oyster Creek would retire by the end of 2019 as part of an agreement with the State of New Jersey to avoid significant costs associated with the construction of cooling towers to meet the State's then new environmental regulations. Since then, like other nuclear sites, Oyster Creek continued to face rising operating costs amid a historically low wholesale power price environment. On February 2, 2018, Exelon announced that Generation will permanently cease generation operations at the Oyster Creek nuclear plant at the end of its current operating cycle and permanently ceased generation operations in September 2018.

As a result of these early nuclear plant retirement decisions, Exelon and Generation recognized one-time charges in Operating and maintenance expense related to materials and supplies inventory reserve adjustments, employee-related costs and CWIP impairments, among other items. In addition to these one-time charges, annual incremental non-cash charges to earnings stemming from shortening the expected economic useful lives primarily related to accelerated depreciation of plant assets (including any ARC), accelerated amortization of nuclear fuel, and additional ARO accretion expense associated with the changes in decommissioning timing and cost assumptions were also recorded. See Note 15 — Asset Retirement Obligations for additional information on changes to the nuclear decommissioning ARO balance. The total annual impact of these charges by year are summarized in the table below.

Income statement expense (pre-tax)	2018[a]	2017[b]	2016[c]
Depreciation and Amortization			
Accelerated depreciation[d]	$ 539	$ 250	$ 712
Accelerated nuclear fuel amortization	57	12	60
Operating and Maintenance			
One-time charges[e,f]	32	77	26
Change in ARO accretion, net of any contractual offset[g]	—	—	2
Contractual offset for ARC depreciation[g]	—	—	(86)
Total	$ 628	$ 339	$ 714

(a) Reflects incremental accelerated depreciation for TMI and Oyster Creek. The Oyster Creek year-to-date amounts are from February 2, 2018 through September 17, 2018.

(b) Reflects incremental charges for TMI including incremental accelerated depreciation and amortization from May 30, 2017 through December 31, 2017.

(c) Reflects incremental charges for Clinton and Quad Cities including incremental accelerated depreciation and amortization from June 2, 2016 through December 6, 2016. In December 2016, as a result of reversing its retirement decision for Clinton and Quad Cities, Exelon and Generation updated the expected economic useful life for both facilities, to 2027 for Clinton, commensurate with the end of the Illinois ZES, and to 2032 for Quad Cities, the end of its current operating license. Depreciation was therefore adjusted beginning December 7, 2016, to reflect these extended useful life estimates.

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

(e) Primarily includes materials and supplies inventory reserve adjustments, employee related costs and CWIP impairments. Excludes the charge to Operating and maintenance expense from the ARO remeasurement due to the announced sale of Oyster Creek. See Note 5 — Mergers, Acquisitions and Dispositions for additional information.

(f)

In June 2016, as a result of the retirement decision for Clinton and Quad Cities, Exelon and Generation recognized one-time charges of $146 million. In December 2016, as a result of reversing its retirement decision for Clinton and Quad Cities, Exelon and Generation reversed approximately $120 million of these one-time charges initially recorded in June 2016.

(g) For Quad Cities based on the regulatory agreement with the ICC, decommissioning-related activities are offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The offset results in an equal adjustment to the noncurrent payables to ComEd at Generation and an adjustment to the regulatory liabilities at ComEd. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

In 2017, PSEG made public similar financial challenges facing its New Jersey nuclear plants, including Salem, of which Generation owns a 42.59% ownership interest. PSEG is the operator of Salem and also has the decision making authority to retire Salem.

On May 23, 2018, New Jersey enacted legislation that established a ZEC program, similar to that in Illinois and New York, that will provide compensation for nuclear plants that demonstrate to the NJBPU that they meet certain requirements, including that they make a significant contribution to air quality in the state and that their revenues are insufficient to cover their costs and risks. The NJBPU must complete its processes for determining eligibility for, and participation in, the ZEC program by April 18, 2019. On December 19, 2018, PSEG submitted its application for Salem. Assuming the successful implementation of the New Jersey ZEC program and the selection of Salem as one of the qualifying facilities, the New Jersey ZEC program has the potential to mitigate the heightened risk of earlier retirement for Salem. See Note 4 - Regulatory Matters for additional information.

The following table provides the balance sheet amounts as of December 31, 2018 for Generation's ownership share of the significant assets and liabilities associated with Salem that would potentially be impacted by a decision to permanently cease generation operations.

	December 31, 2018
Asset Balances	
Materials and supplies inventory	$ 45
Nuclear fuel inventory, net	118
Completed plant, net	538
Construction work in progress	44
Liability Balances	
Asset retirement obligation	(395)
NRC License Renewal Term	2036 (unit 1) 2040 (unit 2)

Generation's Dresden, Byron, and Braidwood nuclear plants in Illinois are also showing increased signs of economic distress, which could lead to an early retirement, in a market that does not currently compensate them for their unique contribution to grid resiliency and their ability to produce large amounts of energy without carbon and air pollution. The May 2018 PJM capacity auction for the 2021-2022 planning year resulted in the largest volume of nuclear capacity ever not selected in the auction, including all of Dresden, and portions of Byron and Braidwood. Exelon continues to work with stakeholders on state policy solutions, while also advocating for broader market reforms at the regional and federal level.

Other Generation

On March 29, 2018, Generation notified grid operator ISO-NE of its plans to early retire its Mystic Generating Station assets absent regulatory reforms on June 1, 2022, at the end of the current capacity commitment for Mystic Units 7 and 8. Mystic Unit 9 is currently committed through May 2021.

The ISO-NE announced that it would take a three-step approach to fuel security.

- First, on May 1, 2018, ISO-NE made a filing with FERC requesting waiver of certain tariff provisions to allow it to retain Mystic Units 8 and 9 for fuel security for the 2022 - 2024 capacity commitment periods. FERC denied the waiver request on procedural grounds on July 2, 2018 and ordered ISO-NE to (i) make a filing within 60 days providing for the filing of a short-term cost-of-service agreement to address fuel security concerns and (ii) make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

- Second, in accordance with FERC's July 2, 2018 order, on August 31, 2018, ISO-NE made a filing with FERC proposing short-term tariff changes to permit it to retain a resource for fuel security reliability reasons, which FERC accepted on December 3, 2018.
- Third, ISO-NE stated its intention to work with stakeholders to develop long-term market rule changes to address system resiliency considering significant reliability risks identified in ISO-NE's January 2018 fuel security report. Changes to market rules are necessary because critical units to the region, such as Mystic Units 8 and 9, cannot recover future operating costs, including the cost of procuring fuel. In its July 2, 2018 order, FERC ordered ISO-NE to make a filing by July 1, 2019 proposing permanent tariff revisions that would improve its market design to better address regional fuel security concerns. In January 2019, ISO-NE has indicated that it intends to seek an extension of the deadline for this filing to November 15, 2019.

On May 16, 2018, Generation made a filing with FERC to establish cost-of-service compensation and terms and conditions of service for Mystic Units 8 and 9 for the period between June 1, 2022 - May 31, 2024. Among the costs included in the filing are costs associated with the Everett Marine Terminal. On December 20, 2018, FERC issued an order accepting the cost of service agreement reflecting a number of adjustments to the annual fixed revenue requirement and allowing for recovery of a substantial portion of the costs associated with the Everett Marine Terminal. FERC also directed a paper hearing on ROE using a new methodology. Initial and reply briefs on ROE will be due on April 18, 2019 and July 18, 2019. These will be reflected in a compliance filing due February 18, 2019. On January 4, 2019, Generation notified ISO-NE that it will participate in the Forward Capacity Market auction for the 2022 - 2023 capacity commitment period. In addition, on January 22, 2019, Exelon and several other parties filed requests for rehearing of certain findings of the December 20, 2018 order. The request for rehearing does not alter Generation's commitment to participate in the Forward Capacity Auction for the 2022-2023 capacity commitment period.

The following table provides the balance sheet amounts as of December 31, 2018 for Generation's significant assets and liabilities associated with the Mystic Units 8 and 9 and Everett Marine Terminal assets that would potentially be impacted by a decision to permanently cease generation operations.

	December 31, 2018
Asset Balances	
Materials and supplies inventory	$ 30
Fuel inventory	20
Completed plant, net	901
Construction work in progress	9
Liability Balances	
Asset retirement obligation	(1)

To ensure the continued reliable supply of fuel to Mystic Units 8 and 9 while they remain operating, on October 1, 2018, Generation acquired the Everett Marine Terminal in Massachusetts for a purchase price of $81 million, with the majority of the fair value allocated to Property, plant and equipment and no goodwill recorded. Generation also settled its existing long-term gas supply agreement, resulting in a pre-tax gain of $75 million, which is included within Purchased power and fuel expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

9. Jointly Owned Electric Utility Plant (Exelon, Generation, PECO, BGE, PHI, Pepco, DPL and ACE)
Exelon's, Generation's, PECO's, BGE's, Pepco's, DPL's and ACE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2018 and 2017 were as follows:

	Nuclear Generation				Fossil-Fuel Generation	Transmission		Other
	Quad Cities	Peach Bottom	Salem[(a)]	Nine Mile Point Unit 2	Wyman	PA[(b)]	NJ/ DE[(c)]	Other[(d)]
Operator	Generation	Generation	PSEG Nuclear	Generation	FP&L	First Energy	PSEG/ DPL	various
Ownership interest	75.00 %	50.00 %	42.59 %	82.00 %	5.89 %	various	various	various
Exelon’s share at December 31, 2018:								
Plant[(e)]	$ 1,131	$ 1,451	$ 648	$ 910	$ 4	$ 28	$ 103	$ 15
Accumulated depreciation[(e)]	587	523	227	126	3	16	53	13
Construction work in progress	13	15	44	56	—	1	—	—
Exelon’s share at December 31, 2017:								
Plant[(e)]	$ 1,074	$ 1,417	$ 631	$ 839	$ 3	$ 27	$ 102	$ 15
Accumulated depreciation[(e)]	550	461	205	97	3	15	52	13
Construction work in progress	35	18	33	55	—	—	—	—

____

(a) Generation also owns a proportionate share in the fossil-fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2018 and 2017.

(b) PECO, BGE, Pepco, DPL and ACE own a 22%, 7%, 27%, 9% and 8% share, respectively, in 127 miles of 500kV lines located in Pennsylvania as well as a 20.72%, 10.56%, 9.72%, 3.72% and 3.83% share, respectively, of a 500kV substation immediately outside of the Conemaugh fossil-generating station which supplies power to the 500kV lines including, but not limited to, the lines noted above.

(c) PECO, DPL and ACE own a 42.55%, 1% and 13.9% share, respectively in 151.3 miles of 500kV lines located in New Jersey and of the Salem generating plant substation. PECO, DPL and ACE also own a 42.55%, 7.45% and 7.45% share, respectively, in 2.5 miles of 500kV line located over the Delaware River. ACE also has a 21.78% share in a 500kV New Freedom Switching substation.

(d) Generation, DPL and ACE own a 44.24%, 11.91% and 4.83% share, respectively in assets located at Merrill Creek Reservoir located in New Jersey. Pepco, DPL and ACE own a 11.9%, 7.4% and 6.6% share, respectively, in Valley Forge Corporate Center.

(e) Excludes asset retirement costs and general plant.

Exelon’s, Generation’s, PECO's, BGE's, Pepco's, DPL's and ACE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon’s, Generation’s, PECO's, BGE's, Pepco's, DPL's and ACE's share of direct expenses of the jointly owned plants are included in Purchased power and fuel and Operating and maintenance expenses in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income and in Operating and maintenance expenses in PECO's, BGE's, Pepco's, DPL's and ACE's Consolidated Statements of Operations and Comprehensive Income.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

10. Intangible Assets (Exelon, Generation, ComEd, PECO, PHI, Pepco, DPL and ACE)
Goodwill
Exelon’s, ComEd’s and PHI's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2018 and 2017 were as follows:

	Balance at January 1, 2017	Impairment losses	Balance at December 31, 2017	Impairment losses	Balance at December 31, 2018
Exelon					
Gross amount	$ 8,660	$ —	$ 8,660	$ —	$ 8,660
Accumulated impairment loss	1,983	—	1,983	—	1,983
Carrying amount	6,677	—	6,677	—	6,677
ComEd[(a)]					
Gross amount	4,608	—	4,608	—	4,608
Accumulated impairment loss	1,983	—	1,983	—	1,983
Carrying amount	2,625	—	2,625	—	2,625
PHI[(b)]					
Gross amount	4,005	—	4,005	—	4,005
Carrying amount	4,005	—	4,005	—	4,005

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom merger (predecessor parent company of ComEd).
(b) Reflects goodwill recorded in 2016 from the PHI merger.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events occur or circumstances change that would more likely than not reduce the fair value of ComEd's and PHI's reporting units below their carrying amounts. 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. PHI's operating segments are Pepco, DPL and ACE. See Note 24 — Segment Information 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. PHI identified an error related to the allocation of goodwill to its reporting units in 2016 while performing the 2018 annual impairment assessment. As revised in 2018, Exelon's and PHI's $4 billion of goodwill has been assigned to the Pepco, DPL and ACE reporting units in the amounts of $2.1 billion, $1.4 billion and $0.5 billion, respectively, an increase (decrease) of $0.4 billion, $0.3 billion, and $(0.7) billion for Pepco, DPL and ACE, respectively, from the originally reported amounts. This error did not result in a change to the total amount of goodwill recorded at PHI nor would it have resulted in an impairment of PHI's goodwill in 2016 or 2017. Therefore, management has concluded that the error is not material to the previously issued financial statements.
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 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. Exelon's, ComEd's and PHI's accounting policy is to perform a quantitative test of goodwill at least once every three years. 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 authoritative guidance in order to determine the implied fair value of goodwill. If the implied

Table of Contents

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.

2018 and 2017 Goodwill Impairment Assessment. ComEd and PHI qualitatively determined that it was more likely than not that the fair values of their reporting units exceeded their carrying values and, therefore, did not perform quantitative assessments as of November 1, 2018 and 2017 for ComEd and as of November 1, 2017 for PHI. As part of their qualitative assessments, ComEd and PHI evaluated, among other things, management’s best estimate of projected operating and capital cash flows for their businesses, outcomes of recent regulatory proceedings, changes in certain market conditions, including the discount rate and regulated utility peer company EBITDA multiples, while also considering, the passing margin from their last quantitative assessments as of November 1, 2016.

As a result of the reallocation of goodwill to PHI’s reporting units as discussed above, as of November 1, 2018, PHI performed a quantitative test for its 2018 annual goodwill impairment assessment. The first step of the test comparing the estimated fair values of the Pepco, DPL and ACE reporting units to their carrying values, including goodwill, indicated no impairments of goodwill; therefore, no second step was 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 and PHI’s goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2016 and November 1, 2018 for ComEd and PHI, respectively, the estimated fair values of the ComEd, Pepco, DPL and ACE reporting units would have needed to decrease by more than 30%, 30%, 20% and 30%, respectively, for ComEd and PHI to fail the first step of their respective impairment tests.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Other Intangible Assets and Liabilities

Exelon’s, Generation’s, ComEd’s and PHI's other intangible assets and liabilities, included in Unamortized energy contract assets and liabilities and Other deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2018 and 2017:

	December 31, 2018			December 31, 2017		
	Gross	Accumulated Amortization	Net	Gross	Accumulated Amortization	Net
Generation						
Unamortized Energy Contracts[b]	1,957	(1,588)	369	1,938	(1,574)	364
Customer Relationships	325	(162)	163	305	(133)	172
Trade Name	243	(171)	72	243	(148)	95
ComEd						
Chicago Settlement Agreements[c]	162	(148)	14	162	(141)	21
PHI						
Unamortized Energy Contracts[b]	(1,515)	954	(561)	(1,515)	766	(749)
Exelon Corporate						
Software License[a]	95	(34)	61	95	(25)	70
Exelon	$1,267	$ (1,149)	$118	$1,228	$ (1,255)	$(27)

(a) On May 31, 2015, Exelon entered into a long-term software license agreement. Exelon is required to make payments starting August 2015 through May 2024. The intangible asset recognized as a result of these payments is being amortized on a straight-line basis over the contract term.

(b) Includes unamortized energy contract assets and liabilities in Exelon's, Generations and PHI's Consolidated Balance Sheets.

(c) In March 1999 and February 2003, ComEd entered into separate agreements with the City of Chicago and Midwest Generation, LLC. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement.

The following table summarizes the estimated future amortization expense related to intangible assets and liabilities as of December 31, 2018:

For the Years Ending December 31,	Exelon	Generation	ComEd	PHI
2019	$ (32)	$ 70	$ 7	$(119)
2020	(20)	78	7	(115)
2021	(4)	78	—	(92)
2022	(23)	56	—	(89)
2023	(21)	50	—	(81)

The following table summarizes the amortization expense related to intangible assets and liabilities for each of the years ended December 31, 2018, 2017 and 2016:

For the Years Ended December 31,	Exelon [a][b]	Generation [a]	ComEd	PHI[b]
2018	$(109)	$ 63	$ 7	$(188)
2017	(237)	83	7	(336)
2016	(336)	79	7	(430)

(a)

At Exelon and Generation, amortization of unamortized energy contracts totaling $14 million, $35 million and $35 million for the years ended December 31, 2018, 2017 and 2016, respectively, was recorded in Operating revenues or Purchased power and fuel expense in their Consolidated Statements of Operations and Comprehensive Income.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(b) At Exelon and PHI, amortization of the unamortized energy contract fair value adjustment amounts and the corresponding offsetting regulatory asset and liability amounts are amortized through Purchased power and fuel expense in their Consolidated Statements of Operations and Comprehensive Income.

Acquired Intangible Assets and Liabilities

Business combinations require the acquirer to separately recognize identifiable intangible assets in the application of purchase accounting.

Unamortized Energy Contracts. Unamortized energy contract assets and liabilities represent the remaining unamortized fair value of non-derivative energy contracts that Exelon and Generation have acquired. The valuation of unamortized energy contracts 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. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable authoritative guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The Exelon Wind unamortized energy contracts are amortized on a straight-line basis over the period in which the associated contract revenues are recognized as a decrease in Operating revenues within Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. In the case of Antelope Valley, Constellation, CENG, Integrys and ConEdison, the fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition dates through either Operating revenues or Purchased power and fuel expense within Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. 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.

Customer Relationships. The customer relationship intangibles were determined based on a “multi-period excess method” of the income approach. Under this method, the intangible asset’s fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable authoritative guidance. Key assumptions include the customer attrition rate and the discount rate. The authoritative guidance requires that customer-based intangibles be amortized over the period expected to be benefited using the pattern of economic benefit. The amortization of the customer relationships recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Trade Name. The Constellation trade name intangible was determined based on the relief from royalty method of income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The fair value is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable authoritative guidance. Key assumptions include the hypothetical royalty rate and the discount rate. The Constellation trade name intangible is amortized on a straight-line basis over a period of 10 years. The amortization of the trade name is recorded in Depreciation and amortization expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation, PECO, PHI, DPL and ACE)

Exelon’s, Generation’s, PECO's, PHI's, DPL's and ACE's other intangible assets, included in Other current assets and Other deferred debits and other assets in the Consolidated Balance Sheets, include RECs (Exelon, Generation, PHI, DPL and ACE) and AECs (Exelon and PECO). Purchased RECs are recorded at cost on the date they are purchased. The cost of RECs purchased on a stand-alone basis is based on the transaction price, while the cost of RECs acquired through PPAs represents the difference between the total contract price and the market price of energy at contract inception. Generally, revenue for RECs that are sold to a counterparty under a contract that specifically identifies a power plant is recognized at a point in time when the power is produced. This includes both bundled and unbundled REC sales. Otherwise, the revenue is recognized upon physical transfer of the REC to the customer.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes the current and noncurrent Renewable and Alternative Energy Credits as of December 31, 2018 and 2017:

	As of December 31, 2018					
	Exelon	Generation	PECO	PHI	DPL	ACE
Current AEC's	$2	$ —	$ 2	$ —	$ —	$ —
Current REC's	279	270	—	9	8	1
Noncurrent REC's	52	52	—	—	—	—

	As of December 31, 2017					
	Exelon	Generation	PECO	PHI	DPL	ACE
Current AEC's	$1	$ —	$ 1	$ —	$ —	$ —
Current REC's	321	312	—	9	8	1
Noncurrent REC's	27	27	—	—	—	—

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

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of December 31, 2018 and 2017:

Exelon

	December 31, 2018				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$714	$ —	$ 714	$ —	$ 714
Long-term debt (including amounts due within one year)[a]	35,424	—	33,711	2,158	35,869
Long-term debt to financing trusts[b]	390	—	—	400	400
SNF obligation	1,171	—	949	—	949

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$929	$ —	$ 929	$ —	$ 929
Long-term debt (including amounts due within one year)[a]	34,264	—	34,735	1,970	36,705
Long-term debt to financing trusts[b]	389	—	—	431	431
SNF obligation	1,147	—	936	—	936

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

	December 31, 2018				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$8,793	$—	$7,467	$1,443	$8,910
SNF obligation	1,171	—	949	—	949

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$2	$—	$2	$—	$2
Long-term debt (including amounts due within one year)[a]	8,990	—	7,839	1,673	9,512
SNF obligation	1,147	—	936	—	936

ComEd

	December 31, 2018				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$8,101	$—	$8,390	$—	$8,390
Long-term debt to financing trusts[b]	205	—	—	209	209

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$7,601	$—	$8,418	$—	$8,418
Long-term debt to financing trusts[b]	205	—	—	227	227

PECO

	December 31, 2018				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$3,084	$—	$3,157	$50	$3,207
Long-term debt to financing trusts	184	—	—	191	191

	December 31, 2017				
		Fair Value			
	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)[a]	$2,903	$—	$3,194	$—	$3,194
Long-term debt to financing trusts	184	—	—	204	204

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$35	$—	$ 35	$ —	$ 35
Long-term debt (including amounts due within one year)[a]	2,876	—	2,950	—	2,950

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$77	$—	$ 77	$ —	$ 77
Long-term debt (including amounts due within one year)[a]	2,577	—	2,825	—	2,825

PHI

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$179	$—	$179	$ —	$179
Long-term debt (including amounts due within one year)[a]	6,259	—	5,436	665	6,101

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$350	$—	$350	$ —	$350
Long-term debt (including amounts due within one year)[a]	5,874	—	5,722	297	6,019

Pepco

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$40	$—	$ 40	$ —	$ 40
Long-term debt (including amounts due within one year)[a]	2,719	—	2,901	196	3,097

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$26	$—	$ 26	$ —	$ 26
Long-term debt (including amounts due within one year)[a]	2,540	—	3,114	9	3,123

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

DPL

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)(a)	$1,494	$—	$1,303	$193	$1,496

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$216	$—	$216	$ —	$216
Long-term debt (including amounts due within one year)(a)	1,300	—	1,393	—	1,393

ACE

	December 31, 2018				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$139	$—	$139	$ —	$139
Long-term debt (including amounts due within one year)(a)	1,188	—	987	275	1,262

	December 31, 2017				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$108	$—	$108	$ —	$108
Long-term debt (including amounts due within one year)(a)	1,121	—	949	288	1,237

(a) Includes unamortized debt issuance costs which are not fair valued of $216 million, $51 million, $63 million, $23 million, $18 million, $14 million, $34 million, $12 million and $7 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE respectively, as of December 31, 2018. Includes unamortized debt issuance costs which are not fair valued of $201 million, $60 million, $52 million, $17 million, $17 million, $6 million, $32 million, $11 million and $5 million for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE respectively, as of December 31, 2017.
(b) Includes unamortized debt issuance costs which are not fair valued of $0 million and $1 million for Exelon and ComEd, respectively, as of December 31, 2018. Includes unamortized debt issuance costs which are not fair valued of $1 million and $1 million for Exelon and ComEd, respectively, as of December 31, 2017.

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

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

329

bond or note. Due to low trading volume of private placement debt, qualitative factors such as market conditions, low volume of investors and investor demand, this debt is classified as Level 3.

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

SNF Obligation. The carrying amount of Generation’s SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation’s nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation’s discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2030. The carrying amount also includes $119 million and $114 million as of December 31, 2018 and 2017 for the one-time fee obligation associated with closing of the FitzPatrick acquisition on March 31, 2017. The fair value was determined using a similar methodology, however the New York Power Authority's (NYPA) discount rate is used in place of Generation's given the contractual right to reimbursement from NYPA for the obligation; see Note 5 - Mergers, Acquisitions and Dispositions for additional information on Generation's acquisition of FitzPatrick.

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

Recurring Fair Value Measurements

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

- Level 1 — quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to liquidate as of the reporting date.
- Level 2 — inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.
- Level 3 — unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation and Exelon
In accordance with the applicable guidance on fair value measurement, certain investments that are measured at fair value using the NAV per share as a practical expedient are no longer classified within the fair value hierarchy and are included under "Not subject to leveling" in the table below.
The following tables present assets and liabilities measured and recorded at fair value in Exelon's and Generation’s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and 2017:

	Generation					Exelon				
As of December 31, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[a]	$581	$—	$—	$—	$581	$1,243	$—	$—	$—	$1,243
NDT fund investments										
Cash equivalents[b]	252	86	—	—	338	252	86	—	—	338
Equities	2,918	1,591	—	1,381	5,890	2,918	1,591	—	1,381	5,890
Fixed income										
Corporate debt	—	1,593	230	—	1,823	—	1,593	230	—	1,823
U.S. Treasury and agencies	2,081	99	—	—	2,180	2,081	99	—	—	2,180
Foreign governments	—	50	—	—	50	—	50	—	—	50
State and municipal debt	—	149	—	—	149	—	149	—	—	149
Other[c]	—	30	—	846	876	—	30	—	846	876
Fixed income subtotal	2,081	1,921	230	846	5,078	2,081	1,921	230	846	5,078
Middle market lending	—	—	313	367	680	—	—	313	367	680
Private equity	—	—	—	329	329	—	—	—	329	329
Real estate	—	—	—	510	510	—	—	—	510	510
NDT fund investments subtotal[d]	5,251	3,598	543	3,433	12,825	5,251	3,598	543	3,433	12,825

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pledged assets for Zion Station decommissioning										
Cash equivalents	9	—	—	—	9	9	—	—	—	9
Equities	—	—	—	—	—	—	—	—	—	—
Middle market lending	—	—	—	—	—	—	—	—	—	—
Pledged assets for Zion Station decommissioning subtotal	9	—	—	—	9	9	—	—	—	9
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	48	—	—	—	48
Mutual funds	24	—	—	—	24	72	—	—	—	72
Fixed income	—	—	—	—	—	—	15	—	—	15
Life insurance contracts	—	22	—	—	22	—	70	38	—	108
Rabbi trust investments subtotal[(f)]	29	22	—	—	51	120	85	38	—	243
Commodity derivative assets										
Economic hedges	541	2,760	1,470	—	4,771	541	2,760	1,470	—	4,771
Proprietary trading	—	69	77	—	146	—	69	77	—	146
Effect of netting and allocation of collateral[(e)]	(582)	(2,357)	(732)	—	(3,671)	(582)	(2,357)	(732)	—	(3,671)
Commodity derivative assets subtotal	(41)	472	815	—	1,246	(41)	472	815	—	1,246
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	—	—	—	—	—	—	—	—	—
Economic hedges	—	13	—	—	13	—	13	—	—	13
Effect of netting and allocation of collateral	—	(3)	—	—	(3)	—	(3)	—	—	(3)
Interest rate and foreign currency derivative assets subtotal	—	10	—	—	10	—	10	—	—	10
Other investments	—	—	42	—	42	—	—	42	—	42
Total assets	5,829	4,102	1,400	3,433	14,764	6,482	4,265	1,438	3,433	15,618

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2018	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Liabilities										
Commodity derivative liabilities										
Economic hedges	(642)	(2,963)	(1,027)	—	(4,632)	(642)	(2,963)	(1,276)	—	(4,881)
Proprietary trading	—	(73)	(21)	—	(94)	—	(73)	(21)	—	(94)
Effect of netting and allocation of collateral[e]	639	2,581	808	—	4,028	639	2,581	808	—	4,028
Commodity derivative liabilities subtotal	(3)	(455)	(240)	—	(698)	(3)	(455)	(489)	—	(947)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	—	—	—	—	—	(4)	—	—	(4)
Economic hedges	—	(6)	—	—	(6)	—	(6)	—	—	(6)
Effect of netting and allocation of collateral	—	3	—	—	3	—	3	—	—	3
Interest rate and foreign currency derivative liabilities subtotal	—	(3)	—	—	(3)	—	(7)	—	—	(7)
Deferred compensation obligation	—	(35)	—	—	(35)	—	(137)	—	—	(137)
Total liabilities	(3)	(493)	(240)	—	(736)	(3)	(599)	(489)	—	(1,091)
Total net assets	$5,826	$3,609	$1,160	$3,433	$14,028	$6,579	$3,566	$949	$3,433	$14,527

	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Assets										
Cash equivalents[a]	$168	$—	$—	$—	$168	$656	$—	$—	$—	$656
NDT fund investments										
Cash equivalents[b]	135	85	—	—	220	135	85	—	—	220
Equities	4,163	915	—	2,176	7,254	4,163	915	—	2,176	7,254
Fixed income										
Corporate debt	—	1,614	251	—	1,865	—	1,614	251	—	1,865
U.S. Treasury and agencies	1,917	52	—	—	1,969	1,917	52	—	—	1,969
Foreign governments	—	82	—	—	82	—	82	—	—	82
State and municipal debt	—	263	—	—	263	—	263	—	—	263

Other(c)	—	47	—	510	557	—	47	—	510	557
Fixed income subtotal	1,917	2,058	251	510	4,736	1,917	2,058	251	510	4,736

333

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Middle market lending	—	—	397	131	528	—	—	397	131	528
Private equity	—	—	—	222	222	—	—	—	222	222
Real estate	—	—	—	471	471	—	—	—	471	471
NDT fund investments subtotal[d]	6,215	3,058	648	3,510	13,431	6,215	3,058	648	3,510	13,431
Pledged assets for Zion Station decommissioning										
Cash equivalents	2	—	—	—	2	2	—	—	—	2
Equities	—	1	—	—	1	—	1	—	—	1
Middle market lending	—	—	12	24	36	—	—	12	24	36
Pledged assets for Zion Station decommissioning subtotal	2	1	12	24	39	2	1	12	24	39
Rabbi trust investments										
Cash equivalents	5	—	—	—	5	77	—	—	—	77
Mutual funds	23	—	—	—	23	58	—	—	—	58
Fixed income	—	—	—	—	—	—	12	—	—	12
Life insurance contracts	—	22	—	—	22	—	71	22	—	93
Rabbi trust investments subtotal[f]	28	22	—	—	50	135	83	22	—	240
Commodity derivative assets										
Economic hedges	557	2,378	1,290	—	4,225	557	2,378	1,290	—	4,225
Proprietary trading	2	31	35	—	68	2	31	35	—	68
Effect of netting and allocation of collateral[e]	(585)	(1,769)	(635)	—	(2,989)	(585)	(1,769)	(635)	—	(2,989)
Commodity derivative assets subtotal	(26)	640	690	—	1,304	(26)	640	690	—	1,304
Interest rate and foreign currency derivative assets										
Derivatives designated as hedging instruments	—	3	—	—	3	—	6	—	—	6
Economic hedges	—	10	—	—	10	—	10	—	—	10
Effect of netting and allocation of collateral	(2)	(5)	—	—	(7)	(2)	(5)	—	—	(7)
Interest rate and foreign currency derivative assets subtotal	(2)	8	—	—	6	(2)	11	—	—	9
Other investments	—	—	37	—	37	—	—	37	—	37
Total assets	6,385	3,729	1,387	3,534	15,035	6,980	3,793	1,409	3,534	15,716

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					Exelon				
As of December 31, 2017	Level 1	Level 2	Level 3	Not subject to leveling	Total	Level 1	Level 2	Level 3	Not subject to leveling	Total
Liabilities										
Commodity derivative liabilities										
Economic hedges	(712)	(2,226)	(845)	—	(3,783)	(713)	(2,226)	(1,101)	—	(4,040)
Proprietary trading	(2)	(42)	(9)	—	(53)	(2)	(42)	(9)	—	(53)
Effect of netting and allocation of collateral[(e)]	650	2,089	716	—	3,455	651	2,089	716	—	3,456
Commodity derivative liabilities subtotal	(64)	(179)	(138)	—	(381)	(64)	(179)	(394)	—	(637)
Interest rate and foreign currency derivative liabilities										
Derivatives designated as hedging instruments	—	(2)	—	—	(2)	—	(2)	—	—	(2)
Economic hedges	(1)	(8)	—	—	(9)	(1)	(8)	—	—	(9)
Effect of netting and allocation of collateral	2	5	—	—	7	2	5	—	—	7
Interest rate and foreign currency derivative liabilities subtotal	1	(5)	—	—	(4)	1	(5)	—	—	(4)
Deferred compensation obligation	—	(38)	—	—	(38)	—	(145)	—	—	(145)
Total liabilities	(63)	(222)	(138)	—	(423)	(63)	(329)	(394)	—	(786)
Total net assets	$6,322	$3,507	$1,249	$3,534	$14,612	$6,917	$3,464	$1,015	$3,534	$14,930

(a) Generation excludes cash of $283 million and $259 million at December 31, 2018 and 2017 and restricted cash of $39 million and $127 million at December 31, 2018 and 2017. Exelon excludes cash of $458 million and $389 million at December 31, 2018 and 2017 and restricted cash of $80 million and $145 million at December 31, 2018 and 2017 and includes long-term restricted cash of $185 million and $85 million at December 31, 2018 and 2017, which is reported in Other deferred debits in the Consolidated Balance Sheets.

(b) Includes $50 million and $77 million of cash received from outstanding repurchase agreements at December 31, 2018 and 2017, respectively, and is offset by an obligation to repay upon settlement of the agreement as discussed in (d) below.

(c) Includes derivative instruments of $44 million and less than $1 million, which have a total notional amount of $1,432 million and $811 million at December 31, 2018 and 2017, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.

(d)

Excludes net liabilities of $130 million and $82 million at December 31, 2018 and 2017, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, repurchase agreement obligations, and payables related to pending securities purchases. The repurchase agreements are generally short-term in nature with durations generally of 30 days or less.

(e) Excludes net assets of less than $1 million at December 31, 2018 and 2017. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(f) The amount of unrealized gains/(losses) at Generation totaled less than $1 million and $1 million for the years ended December 31, 2018 and 2017, respectively. The amount of unrealized gains/(losses) at Exelon totaled $1 million for the years ended December 31, 2018 and 2017, respectively.

(g) Collateral posted/(received) from counterparties totaled $57 million, $224 million and $76 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2018. Collateral posted/(received) from counterparties totaled $65 million, $320 million and $81 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2017.

(h) Of the collateral posted/(received), $(94) million and $(117) million represents variation margin on the exchanges as of December 31, 2018 and 2017, respectively.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon and Generation hold investments without readily determinable fair values with carrying amounts of $72 million as of December 31, 2018. Changes were immaterial in fair value, cumulative adjustments and impairments for the year ended December 31, 2018.

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value in ComEd's, PECO's and BGE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and 2017:

	ComEd				PECO				BGE			
As of December 31, 2018	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[a]	$209	$ —	$ —	$209	$111	$ —	$ —	$111	$4	$ —	$ —	$4
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[b]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	209	—	—	209	118	10	—	128	10	—	—	10
Liabilities												
Deferred compensation obligation	—	(6)	—	(6)	—	(10)	—	(10)	—	(5)	—	(5)
Mark-to-market derivative liabilities[c]	—	—	(249)	(249)	—	—	—	—	—	—	—	—
Total liabilities	—	(6)	(249)	(255)	—	(10)	—	(10)	—	(5)	—	(5)
Total net assets (liabilities)	$209	$ (6)	$(249)	$(46)	$118	$ —	$ —	$118	$10	$ (5)	$ —	$5

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	ComEd				PECO				BGE			
As of December 31, 2017	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[a]	$ 98	$ —	$ —	$ 98	$ 228	$ —	$ —	$ 228	$ —	$ —	$ —	$ —
Rabbi trust investments												
Mutual funds	—	—	—	—	7	—	—	7	6	—	—	6
Life insurance contracts	—	—	—	—	—	10	—	10	—	—	—	—
Rabbi trust investments subtotal[b]	—	—	—	—	7	10	—	17	6	—	—	6
Total assets	98	—	—	98	235	10	—	245	6	—	—	6
Liabilities												
Deferred compensation obligation	—	(8)	—	(8)	—	(11)	—	(11)	—	(5)	—	(5)
Mark-to-market derivative liabilities[c]	—	—	(256)	(256)	—	—	—	—	—	—	—	—
Total liabilities	—	(8)	(256)	(264)	—	(11)	—	(11)	—	(5)	—	(5)
Total net assets (liabilities)	$ 98	$ (8)	$ (256)	$ (166)	$ 235	$ (1)	$ —	$ 234	$ 6	$ (5)	$ —	$ 1

(a) ComEd excludes cash of $93 million and $45 million at December 31, 2018 and 2017 and restricted cash of $28 million at December 31, 2018 and includes long-term restricted cash of $166 million and $62 million at December 31, 2018 and December 31, 2017, which is reported in Other deferred debits in the Consolidated Balance Sheets. PECO excludes cash of $24 million and $47 million at December 31, 2018 and 2017. BGE excludes cash of $7 million and $17 million at December 31, 2018 and 2017 and restricted cash of $2 million and $1 million at December 31, 2018 and December 31, 2017.

(b) The amount of unrealized gains/(losses) at ComEd, PECO and BGE totaled less than $1 million for the years ended December 31, 2018 and December 31, 2017.

(c) The Level 3 balance consists of the current and noncurrent liability of $26 million and $223 million, respectively, at December 31, 2018, and $21 million and $235 million, respectively, at December 31, 2017, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI, Pepco, DPL and ACE
The following tables present assets and liabilities measured and recorded at fair value in PHI's, Pepco's, DPL's and ACE's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2018 and 2017:

	As of December 31, 2018				As of December 31, 2017			
PHI	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$147	$ —	$ —	$147	$83	$ —	$ —	$83
Rabbi trust investments								
Cash equivalents	42	—	—	42	72	—	—	72
Mutual Funds	13	—	—	13	—	—	—	—
Fixed income	—	15	—	15	—	12	—	12
Life insurance contracts	—	22	38	60	—	23	22	45
Rabbi trust investments subtotal[(b)]	55	37	38	130	72	35	22	129
Total assets	202	37	38	277	155	35	22	212
Liabilities								
Deferred compensation obligation	—	(21)	—	(21)	—	(25)	—	(25)
Mark-to-market derivative liabilities	—	—	—	—	(1)	—	—	(1)
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—
Total liabilities	—	(21)	—	(21)	—	(25)	—	(25)
Total net assets	$202	$ 16	$ 38	$256	$155	$ 10	$ 22	$187

	Pepco				DPL				ACE			
As of December 31, 2018	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[(a)]	$38	$ —	$ —	$38	$16	$ —	$ —	$16	$23	$ —	$ —	$ 23
Rabbi trust investments												
Cash equivalents	41	—	—	41	—	—	—	—	—	—	—	—
Fixed income	—	5	—	5	—	—	—	—	—	—	—	—
Life insurance contracts	—	22	37	59	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[(b)]	41	27	37	105	—	—	—	—	—	—	—	—
Total assets	79	27	37	143	16	—	—	16	23	—	—	23
Liabilities												
Deferred compensation obligation	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total liabilities	—	(3)	—	(3)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$79	$ 24	$ 37	$140	$16	$ (1)	$ —	$15	$23	$ —	$ —	$ 23

338

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Pepco				DPL				ACE			
As of December 31, 2017	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents[a]	$36	$ —	$ —	$36	$ —	$ —	$ —	$ —	$29	$ —	$ —	$ 29
Rabbi trust investments												
Cash equivalents	44	—	—	44	—	—	—	—	—	—	—	—
Fixed income	—	12	—	12	—	—	—	—	—	—	—	—
Life insurance contracts	—	23	22	45	—	—	—	—	—	—	—	—
Rabbi trust investments subtotal[b]	44	35	22	101	—	—	—	—	—	—	—	—
Total assets	80	35	22	137	—	—	—	—	29	—	—	29
Liabilities												
Deferred compensation obligation	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Mark-to-market derivative liabilities	—	—	—	—	(1)	—	—	(1)	—	—	—	—
Effect of netting and allocation of collateral	—	—	—	—	1	—	—	1	—	—	—	—
Mark-to-market derivative liabilities subtotal	—	—	—	—	—	—	—	—	—	—	—	—
Total liabilities	—	(4)	—	(4)	—	(1)	—	(1)	—	—	—	—
Total net assets (liabilities)	$80	$ 31	$ 22	$133	$ —	$ (1)	$ —	$ (1)	$29	$ —	$ —	$ 29

(a) PHI excludes cash of $39 million and $12 million at December 31, 2018 and 2017 and includes long term restricted cash of $19 million and $23 million at December 31, 2018 and 2017 which is reported in Other deferred debits in the Consolidated Balance Sheets. Pepco excludes cash of $15 million and $4 million at December 31, 2018 and 2017. DPL excludes cash of $8 million and $2 million at December 31, 2018 and 2017. ACE excludes cash of $7 million and $2 million at December 31, 2018 and 2017 and includes long-term restricted cash of $19 million and $23 million at December 31, 2018 and 2017 at December 31, 2018 and 2017 which is reported in Other deferred debits in the Consolidated Balance Sheets.

(b) The amount of unrealized gains/(losses) at PHI totaled $1 million for the years ended December 31, 2018 and 2017, respectively. The amount of unrealized gains/(losses) at Pepco totaled less than $1 million for the years ended December 31, 2018 and 2017, respectively.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2018 and 2017:

	Generation					ComEd	PHI		Exelon
For the year ended December 31, 2018	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts	Eliminated in Consolidation (c)	Total
Balance as of January 1, 2018	$648	$ 12	$ 552	$ 37	$ 1,249	$ (256)	$ 22	$ —	$ 1,015
Total realized / unrealized gains (losses)									
Included in net income	—	—	(105) (a)	3	(102)	—	4	—	(98)
Included in noncurrent payables to affiliates	(1)	—	—	—	(1)	—	—	1	—
Included in payable for Zion Station decommissioning	—	7	—	—	7	—	—	—	7
Included in regulatory assets/liabilities	—	—	—	—	—	7 (b)	—	(1)	6
Change in collateral	—	—	(5)	—	(5)	—	—	—	(5)
Purchases, sales, issuances and settlements									
Purchases	36	1	190 (e)	4	231	—	—	—	231
Sales	—	(20)	(4)	—	(24)	—	—	—	(24)
Issuances	—	—	—	—	—	—	—	—	—
Settlements	(140)	—	5	—	(135)	—	12	—	(123)
Transfers into Level 3	—	—	(22) (d)	—	(22)	—	—	—	(22)
Transfers out of Level 3	—	—	(36) (d)	(2)	(38)	—	—	—	(38)
Other miscellaneous	—	—	—		—	—	—	—	—
Balance as of December 31, 2018	$543	$ —	$ 575	$ 42	$ 1,160	$ (249)	$ 38	$ —	$949
The amount of total (losses) gains included in income attributed to the change in unrealized (losses) gains related to assets and liabilities held as of December 31, 2018	$(5)	$ —	$ 165	$ 3	$ 163	$ —	$ —	$ —	$163

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Generation					ComEd	PHI		Exelon
For the year ended December 31, 2017	NDT Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives	Life Insurance Contracts [c]	Eliminated in Consolidation	Total
Balance as of January 1, 2017	$677	$ 19	$ 493	$ 42	$ 1,231	$ (258)	$ 20	$ —	$993
Total realized / unrealized gains (losses)									
Included in net income	3	—	(90) [a]	3	(84)	—	3	—	(81)
Included in noncurrent payables to affiliates	6	—	—	—	6	—	—	(6)	—
Included in payable for Zion Station decommissioning	—	(8)	—	—	(8)	—		—	(8)
Included in regulatory assets/liabilities	—	—	—	—	—	2 [b]	—	6	8
Change in collateral	—	—	20	—	20	—	—	—	20
Purchases, sales, issuances and settlements									
Purchases	64	1	178	5	248	—	—	—	248
Sales	—	—	(16)	—	(16)	—	—	—	(16)
Issuances	—	—	—	—	—	—	(1)	—	(1)
Settlements	(102)	—	(8)	—	(110)	—	—	—	(110)
Transfers into Level 3	—	—	(6) [d]	—	(6)	—	—	—	(6)
Transfers out of Level 3	—	—	(50) [d]	(11)	(61)	—	—	—	(61)
Other miscellaneous	$—	$ —	$ 31	$ (2)	$ 29	$ —	$ —	$ —	$29
Balance as of December 31, 2017	$648	$ 12	$ 552	$ 37	$ 1,249	$ (256)	$ 22	$ —	$1,015
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2017	$1	$ —	$ 254	$ 3	$ 258	$ —	$ 3	$ —	$261

(a) Includes a reduction for the reclassification of $265 million and $352 million of realized gains due to the settlement of derivative contracts for the years ended December 31, 2018 and 2017, respectively.

(b) Includes $24 million of decreases in fair value and an increase for realized losses due to settlements of $17 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2018. Includes $18 million of decreases in fair value and an increase for realized losses due to settlements of $20 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the year ended December 31, 2017.

(c) The amounts represented are life insurance contracts at Pepco.

(d)

Transfers into and out of Level 3 generally occur when the contract tenor becomes less and more observable respectively, primarily due to changes in market liquidity or assumptions for certain commodity contracts.

(e) Includes $(19) million of fair value from contracts acquired as a result of the Everett Marine Terminal acquisition

341

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2018 and 2017:

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net
Total (losses) gains included in net income for the year ended December 31, 2018	$(7)	$ (93)	$ 3	$ 4	$(7)	$ (93)	$ 4	$ 3
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2018	144	21	(2)	—	144	21	—	(2)

	Generation			PHI	Exelon			
	Operating Revenues	Purchased Power and Fuel	Other, net	Operating and Maintenance	Operating Revenues	Purchased Power and Fuel	Operating and Maintenance	Other, net
Total gains (losses) included in net income for the year ended December 31, 2017	$28	$ (126)	$ 6	$ 3	$28	$ (126)	$ 3	$ 6
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2017	290	(36)	4	3	290	(36)	3	4

Valuation Techniques Used to Determine Fair Value

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

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

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

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

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the

Table of Contents

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

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

Derivative instruments consisting primarily of futures and interest rate swaps to manage risk are recorded at fair value. Over the counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over the counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

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

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

As of December 31, 2018, Generation has outstanding commitments to invest in fixed income, middle market lending, private equity and real estate investments of approximately $127 million, $224 million, $326 million and $273 million, respectively. These commitments will be funded by Generation’s existing NDT funds.

Concentrations of Credit Risk. Generation evaluated its NDT portfolios for the existence of significant concentrations of credit risk as of December 31, 2018. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2018, there were no significant concentrations (generally defined as greater than 10 percent) of risk in Generation's NDT assets.
See Note 15 — Asset Retirement Obligations for additional information on the NDT fund investments.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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

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

Exelon may utilize fixed-to-floating interest rate swaps as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 12 — Derivative Financial Instruments for additional information on mark-to-market derivatives.

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

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

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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

NDT Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). For middle market lending and certain corporate debt securities investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on discounting the forecasted cash flows, market-based comparable data, credit and liquidity factors, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied for factors such as size, marketability, credit risk and relative performance.

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Therefore, Generation has not disclosed such inputs.

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

Mark-to-Market Derivatives (Exelon, Generation and ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

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

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

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately $3.18 and $0.64 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 12 — Derivative Financial Instruments for additional information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.
The following tables present the significant inputs to the forward curve used to value these positions:

Type of trade	Fair Value at December 31, 2018	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic hedges (Exelon and Generation)[a][b]	$ 443	Discounted Cash Flow	Forward power price	$12 - $174
			Forward gas price	$0.78 - $12.38
		Option Model	Volatility percentage	10% - 277%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation)[a][b]	$ 56	Discounted Cash Flow	Forward power price	$14 - $174
Mark-to-market derivatives (Exelon and ComEd)	$ (249)	Discounted Cash Flow	Forward heat rate[c]	10x - 11x
			Marketability reserve	4% - 8%
			Renewable factor	86% - 120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions of $76 million as of December 31, 2018.
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Type of trade	Fair Value at December 31, 2017	Valuation Technique	Unobservable Input	Range	
Mark-to-market derivatives—Economic hedges (Exelon and Generation)[a][b]	$ 445	Discounted Cash Flow	Forward power price	$3	-$124
			Forward gas price	$1.27	-$12.80
		Option Model	Volatility percentage	11%	-139%
Mark-to-market derivatives—Proprietary trading (Exelon and Generation)[a][b]	$ 26	Discounted Cash Flow	Forward power price	$14	-$94
Mark-to-market derivatives (Exelon and ComEd)	$ (256)	Discounted Cash Flow	Forward heat rate[c]	9x	-10x
			Marketability reserve	4%	-8%
			Renewable factor	88%	-120%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
(b) The fair values do not include cash collateral posted on level three positions $81 million as of December 31, 2017.
(c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

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

12. Derivative Financial Instruments (All Registrants)

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

Commodity Price Risk (All Registrants)

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and financial derivative contracts, including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and commodity products. The Registrants believe these instruments, which are either determined to be non-derivative or classified as economic hedges, mitigate exposure to fluctuations in commodity prices.

Derivative authoritative guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings immediately. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedges and fair value hedges. For Generation, all derivative

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

economic hedges related to commodities are recorded at fair value through earnings for the consolidated company, referred to as economic hedges in the following tables. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation’s energy marketing portfolio but represent a small portion of Generation’s overall energy marketing activities.

Fair value authoritative guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Combined Notes to Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation’s use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation’s energy-related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including margin on exchange positions, is aggregated in the collateral and netting column. As of December 31, 2018, $2 million of cash collateral posted with external counterparties and an additional $12 million of cash collateral posted with ComEd, and as of December 31, 2017, $4 million of cash collateral held, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or had no positions to offset as of the balance sheet date. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

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

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

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

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the derivative fair value balances related to commodity contracts recorded by the Registrants as of December 31, 2018:

Description	Generation Economic Hedges	Generation Proprietary Trading	Generation Collateral and Netting[(a)(d)]	Generation Subtotal[(b)]	ComEd Economic Hedges[(c)]	Exelon Total Derivatives
Mark-to-market derivative assets (current assets)	$3,505	$ 105	$ (2,809)	$ 801	$ —	$ 801
Mark-to-market derivative assets (noncurrent assets)	1,266	41	(862)	445	—	445
Total mark-to-market derivative assets	4,771	146	(3,671)	1,246	—	1,246
Mark-to-market derivative liabilities (current liabilities)	(3,429)	(74)	3,056	(447)	(26)	(473)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,203)	(20)	972	(251)	(223)	(474)
Total mark-to-market derivative liabilities	(4,632)	(94)	4,028	(698)	(249)	(947)
Total mark-to-market derivative net assets (liabilities)	$139	$ 52	$ 357	$ 548	$ (249)	$ 299

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

(b) Current and noncurrent assets are shown net of collateral of $121 million and $51 million, respectively, and current and noncurrent liabilities are shown net of collateral of $125 million and $60 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $357 million at December 31, 2018.

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

(d) Of the collateral posted/(received), $(94) million represents variation margin on the exchanges.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the derivative fair value balances related to commodity contracts recorded by the Registrants as of December 31, 2017:

Description	Generation				ComEd	Exelon
	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)(d)]	Subtotal[(b)]	Economic Hedges[(c)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$3,061	$ 56	$ (2,144)	$ 973	$ —	$ 973
Mark-to-market derivative assets (noncurrent assets)	1,164	12	(845)	331	—	331
Total mark-to-market derivative assets	4,225	68	(2,989)	1,304	—	1,304
Mark-to-market derivative liabilities (current liabilities)	(2,646)	(43)	2,480	(209)	(21)	(230)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,137)	(10)	975	(172)	(235)	(407)
Total mark-to-market derivative liabilities	(3,783)	(53)	3,455	(381)	(256)	(637)
Total mark-to-market derivative net assets (liabilities)	$442	$ 15	$ 466	$ 923	$ (256)	$ 667

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

(b) Current and noncurrent assets are shown net of collateral of $169 million and $53 million, respectively, and current and noncurrent liabilities are shown net of collateral of $167 million and $77 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $466 million at December 31, 2017.

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

(d) Of the collateral posted/(received), $(117) million represents variation margin on the exchanges.

Economic Hedges (Commodity Price Risk)

Within Exelon, Generation has the most exposure to commodity price risk. As such, Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power and gas sales, fuel and power purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. To manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from expected sales of power and gas and purchases of power and fuel. The objectives for executing such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis. For the years ended December 31, 2018, 2017 and 2016, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also located in the "Net fair value changes related to derivatives" in the Consolidated Statements of Cash Flows.

	For the Years Ended December 31,		
	2018	2017	2016
Income Statement Location	Gain (Loss)		
Operating revenues	$(270)	$(126)	$(490)
Purchased power and fuel	(47)	(43)	459
Total Exelon and Generation	$(317)	$(169)	$(31)

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation’s owned and contracted generation positions that have not been hedged. Generation hedges commodity

350

Table of Contents

price risk on a ratable basis over three-year periods. As of December 31, 2018, the percentage of expected generation hedged for the Mid-Atlantic, Midwest, New York and ERCOT reportable segments is 89%-92%, 56%-59% and 32%-35% for 2019, 2020 and 2021, respectively.

On December 17, 2010, ComEd executed several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 4 — Regulatory Matters for additional information.

PECO’s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches to achieve system supply reliability at the least cost. PECO’s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO’s natural gas supply and asset management agreements that are derivatives either qualify for the NPNS scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2018 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2018 and previous PGC settlements, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO’s gas-hedging program is designed to cover about 20% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO’s results of operations and financial position as natural gas costs are fully recovered from customers under the PGC.

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

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

Pepco has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and DCPSC. The SOS rates charged recover Pepco's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for residential and commercial rate classes. Pepco’s commodity price risk related to electric supply procurement is limited. Pepco locks in fixed prices for its SOS requirements through full requirements contracts.

Certain of Pepco’s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other Pepco full requirements contracts are not derivatives.

DPL has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC and the DPSC. The SOS rates charged recover DPL's wholesale power supply costs. In Delaware, DPL is also entitled to recover a Reasonable Allowance for Retail Margin (RARM). The RARM includes a fixed annual margin of approximately $2.75 million, plus an incremental cost component and a cash working capital allowance. In Maryland, DPL charges an administrative fee intended to allow it to recover its administrative

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

costs. DPL locks in fixed prices for its SOS requirements through full requirements contracts. DPL’s commodity price risk related to electric supply procurement is limited. Certain of DPL’s full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other DPL full requirements contracts are not derivatives.

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

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

Proprietary Trading (Commodity Price Risk)

Generation also executes commodity derivatives for proprietary trading purposes. Proprietary trading includes all contracts executed with the intent of benefiting from shifts or changes in market prices as opposed to those executed 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 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 are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall revenue from energy marketing activities. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income. For the years ended December 31, 2018, 2017 and 2016, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses) which are also included in the "Net fair value changes related to derivatives" in the Consolidated Statements of Cash Flows. The Utility Registrants do not execute derivatives for proprietary trading purposes.

	For the Years Ended December 31,		
	2018	2017	2016
Income Statement Location	Gain		
Operating revenues	$17	$ 6	$ 2

352

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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 also utilize interest rate swaps, which are treated as economic hedges, to manage their interest rate exposure. To manage foreign exchange rate exposure associated with international commodity purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are treated as economic hedges. Below is a summary of the interest rate and foreign exchange hedge balances as of December 31, 2018:

	Generation			Exelon Corporate	Exelon
Description	Economic Hedges	Collateral and Netting[(a)]	Subtotal	Economic Hedges	Total
Mark-to-market derivative assets (current assets)	$ 5	$ (2)	$ 3	$ —	$ 3
Mark-to-market derivative assets (noncurrent assets)	8	(1)	7	—	7
Total mark-to-market derivative assets	13	(3)	10	—	10
Mark-to-market derivative liabilities (current liabilities)	(4)	2	(2)	—	(2)
Mark-to-market derivative liabilities (noncurrent liabilities)	(2)	1	(1)	(4)	(5)
Total mark-to-market derivative liabilities	(6)	3	(3)	(4)	(7)
Total mark-to-market derivative net assets (liabilities)	$ 7	$ —	$ 7	$ (4)	$ 3

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

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2017:

	Generation				Exelon Corporate	Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting[(a)]	Subtotal	Derivatives Designated as Hedging Instruments	Total
Mark-to-market derivative assets (current assets)	$—	$ 10	$ (7)	$ 3	$ —	$ 3
Mark-to-market derivative assets (noncurrent assets)	3	—	—	3	3	6
Total mark-to-market derivative assets	3	10	(7)	6	3	9
Mark-to-market derivative liabilities (current liabilities)	(2)	(7)	7	(2)	—	(2)
Mark-to-market derivative liabilities (noncurrent liabilities)	—	(2)	—	(2)	—	(2)
Total mark-to-market derivative liabilities	(2)	(9)	7	(4)	—	(4)
Total mark-to-market derivative net assets (liabilities)	$1	$ 1	$ —	$ 2	$ 3	$ 5

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

Economic Hedges (Interest Rate and Foreign Exchange Risk)

Exelon and Generation execute these instruments to mitigate exposure to fluctuations in interest rates or foreign exchange but for which the fair value or cash flow hedge elections were not made. On July 1, 2018, Exelon de-designated its fair value hedges related to interest rate risk and Generation de-designated its cash flow hedges related to interest rate risk. The amount deferred in AOCI associated with the previously designated cash flow hedges will be reclassified into earnings as the underlying forecasted transaction occurs. The result of this de-designation is that all economic hedges for interest rate swaps will be recorded at fair value through earnings going forward, referred to as economic hedges in the following tables.

The following table provides notional amounts outstanding held by Exelon and Generation at December 31, 2018 related to interest rate swaps and foreign currency exchange rate swaps.

	Generation	Exelon Corporate	Exelon
Foreign currency exchange rate swaps	$ 268	$ —	$268
Interest rate swaps	620	800	1,420
Total	$ 888	$ 800	$1,688

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides notional amounts outstanding held by Exelon and Generation at December 31, 2017 related to interest rate swaps and foreign currency exchange rate swaps.

	Generation	Exelon Corporate	Exelon
Foreign currency exchange rate swaps	$ 94	$ —	$ 94
Interest rate swaps[(a)]	1	—	1
Total	$ 95	$ —	$ 95

____

(a) On July 1, 2018, Exelon and Generation de-designated its fair value and cash flow hedges. The table excludes amounts of $800 million of fixed-to-floating hedges that were previously designated as fair value hedges by Exelon and $636 million of floating-to-fixed hedges that were previously designated as cash flow hedges by Exelon and Generation as of December 31, 2017.

For the years ended December 31, 2018, 2017 and 2016, Exelon and Generation recognized the following net pre-tax mark-to-market gains (losses) in the Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s and Generation’s Consolidated Statements of Cash Flows.

		For the Years Ended December 31,		
		2018	2017	2016
	Income Statement Location	Gain (Loss)		
Generation	Operating Revenues	$7	$(6)	$(10)
Generation	Purchased Power and Fuel	(9)	—	—
Generation	Interest Expense	(7)	(3)	—
Total Generation		$(9)	$(9)	$(10)

		For the Years Ended December 31,		
		2018	2017	2016
	Income Statement Location	Gain (Loss)		
Exelon	Operating Revenues	$7	$(6)	$(10)
Exelon	Purchased Power and Fuel	(9)	—	—
Exelon	Interest Expense	(4)	(3)	—
Total Exelon		$(6)	$(9)	$(10)

Fair Value Hedges (Interest Rate Risk)

For derivative instruments that qualify and are designated as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in earnings immediately. Exelon had no fixed-to-floating swaps designated as fair value hedges as of December 31, 2018 and had $800 million notional amounts designated as fair value hedges as of December 31, 2017. Exelon and Generation include the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps as follows:

	Year Ended December 31,					
	2018	2017	2016	2018	2017	2016
Income Statement Location	Loss on Swaps			Gain on Borrowings		

Exelon	Interest expense	$(11)	$(13)	$(9)	$20	$28	$23

During the years ended December 31, 2018, 2017 and 2016, the impact on the results of operations due to ineffectiveness from fair value hedges were gains of $9 million, $15 million and $14 million, respectively.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Cash Flow Hedges (Interest Rate Risk)
For derivative instruments that qualify and are designated as cash flow hedges, the gain or loss on the effective portion of the derivative will be deferred in AOCI and reclassified into earnings when the underlying transaction occurs. Exelon and Generation have no floating-to-fixed swaps designated as cash flow hedges as of December 31, 2018, and had $636 million notional amounts designated as cash flow hedges as of December 31, 2017.
The tables below provide the activity of OCI related to cash flow hedges for the years ended December 31, 2018 and 2017, containing information about the changes in the fair value of cash flow hedges and the reclassification from AOCI into results of operations. The amounts reclassified from AOCI, when combined with the impacts of the hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge AOCI Activity, Net of Income Tax	
For the Year Ended December 31, 2018	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at December 31, 2017		$ (16)	$ (14)
Effective portion of changes in fair value		11	11
Reclassifications from AOCI to net income	Interest expense	1	1
AOCI derivative loss at December 31, 2018		$ (4)	$ (2)

		Total Cash Flow Hedge AOCI Activity, Net of Income Tax	
For the Year Ended December 31, 2017	Income Statement Location	Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
AOCI derivative loss at December 31, 2016		$ (19)	$ (17)
Effective portion of changes in fair value		(1)	(1)
Reclassifications from AOCI to net income	Interest expense	4 (a)	4 (a)
AOCI derivative loss at December 31, 2017		$ (16)	$ (14)

(a) Amount is net of related income tax expense of $1 million for the year ended December 31, 2017.

During the years ended December 31, 2018, 2017 and 2016, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial. The estimated amount of existing gains and losses that are reported in AOCI at the reporting date that are expected to be reclassified into earnings within the next twelve months is immaterial.
Proprietary Trading (Interest Rate and Foreign Exchange Risk)
Generation also executes derivative contracts for proprietary trading purposes to hedge risk associated with the interest rate and foreign exchange components of underlying commodity positions. Gains and losses associated with proprietary trading are reported as Operating revenues in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. For the years ended December 31, 2018, 2017 and 2016, Exelon and Generation recognized the following net pre-tax commodity mark-to-market gains (losses).

	For the Years Ended December 31,		
	2018	2017	2016
Income Statement Location	Loss		
Operating revenues	$—	$(1)	$(1)

356

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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

The following tables provide information on Generation’s credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2018. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below exclude credit risk exposure from individual retail counterparties, nuclear fuel procurement contracts and exposure through RTOs, ISOs, NYMEX, ICE, NASDAQ, NGX and Nodal commodity exchanges. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO, BGE, Pepco, DPL and ACE of $43 million, $30 million, $24 million, $28 million, $7 million and $5 million as of December 31, 2018, respectively.

Rating as of December 31, 2018	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	$ 795	$ —	$ 795	1	$ 153
Non-investment grade	133	45	88	—	—
No external ratings					
Internally rated — investment grade	181	1	180	—	—
Internally rated — non-investment grade	92	6	86	—	—
Total	$ 1,201	$ 52	$ 1,149	1	$ 153

Net Credit Exposure by Type of Counterparty	December 31, 2018
Financial institutions	$ 12
Investor-owned utilities, marketers, power producers	737
Energy cooperatives and municipalities	324
Other	76
Total	$ 1,149

(a) As of December 31, 2018, credit collateral held from counterparties where Generation had credit exposure included $17 million of cash and $35 million of letters of credit. The credit collateral does not include non-liquid collateral.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on daily, updated 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 on a given day, the suppliers are required to

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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. The unsecured credit used by the suppliers represents ComEd’s net credit exposure. As of December 31, 2018, ComEd’s net credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd’s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 4 — Regulatory Matters for additional information.

PECO’s unsecured credit used by electric suppliers represents PECO’s net credit exposure. As of December 31, 2018, PECO had no material net credit exposure to electric suppliers.

PECO’s natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO’s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. As of December 31, 2018, PECO had no material credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE’s counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 4 — Regulatory Matters for additional information.

BGE’s full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier’s performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. As of December 31, 2018, BGE had no material net credit exposure to suppliers.

BGE’s regulated gas business is exposed to market-price risk. At December 31, 2018, BGE had credit exposure of $3 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

Pepco’s, DPL's and ACE's power procurement contracts provide suppliers with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier’s lowest credit rating from the major credit rating agencies and the supplier’s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier’s unsecured credit limit. The unsecured credit used by the suppliers represents Pepco’s, DPL's and ACE's net credit exposure. As of December 31, 2018, Pepco’s, DPL's and ACE's net credit exposures to suppliers were immaterial.

Pepco is permitted to recover its costs of procuring energy through the MDPSC-approved and DCPSC-approved procurement tariffs. DPL is permitted to recover its costs of procuring energy through the MDPSC-approved and DPSC-approved procurement tariffs. ACE is permitted to recover its costs of procuring energy through the NJBPU-approved procurement tariffs. Pepco’s, DPL's and ACE's counterparty credit risks are mitigated by their ability to recover realized energy costs through customer rates. See Note 4 — Regulatory Matters for additional information.

DPL’s natural gas procurement plan is reviewed and approved annually on a prospective basis by the DPSC. DPL’s counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the GCR, which allows DPL to adjust rates annually to reflect realized natural gas prices. To the extent that the fair value of the transactions in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. Exchange-traded contracts are required to be fully collateralized without regard to the credit rating of the holder. As of December 31, 2018, DPL's credit exposure under its natural gas supply and asset management agreements was immaterial.

Collateral (All Registrants)

As part of the normal course of business, Generation routinely enters into physically or financially settled contracts for the purchase and sale of electric capacity, electricity, fuels, emissions allowances and other energy-related products. Certain of Generation’s derivative instruments contain provisions that require Generation to post collateral.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation also enters into commodity transactions on exchanges where the exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.
The aggregate fair value of all derivative instruments with credit-risk related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

	For the Years Ended December 31,	
Credit-Risk Related Contingent Feature	2018	2017
Gross fair value of derivative contracts containing this feature[(a)]	$ (1,723)	$ (926)
Offsetting fair value of in-the-money contracts under master netting arrangements[(b)]	1,105	577
Net fair value of derivative contracts containing this feature[(c)]	$ (618)	$ (349)

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

Generation had cash collateral posted of $418 million and letters of credit posted of $367 million, and cash collateral held of $47 million and letters of credit held of $44 million as of December 31, 2018 for external counterparties with derivative positions. Generation had cash collateral posted of $497 million and letters of credit posted of $293 million and cash collateral held of $35 million and letters of credit held of $33 million at December 31, 2017 for external counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of $2.1 billion and $1.8 billion as of December 31, 2018 and 2017, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.
Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on

any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2018, Generation’s and Exelon's swaps were in an asset position with a fair value of $7 million and $3 million, respectively.

See Note 24 — Segment Information for additional information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2018, ComEd held approximately $38 million in collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's ZEC contracts, collateral postings are required to cover a percentage of the ZEC contract value. ComEd's REC contracts require collateral postings that are either a fixed price per REC or a percentage of the REC contract value. As of December 31, 2018, ComEd held approximately $31 million in collateral from suppliers for REC and ZEC contract obligations. Under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2018, ComEd held approximately $19 million in collateral from suppliers for the long-term renewable energy contracts. If ComEd lost its investment grade credit rating as of December 31, 2018, it would have been required to post approximately $7 million of collateral to its counterparties. See Note 4 — Regulatory Matters for additional information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2018, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2018, PECO could have been required to post approximately $39 million of collateral to its counterparties.

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

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2018, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2018, BGE could have been required to post approximately $69 million of collateral to its counterparties.

DPL's natural gas procurement contracts contain provisions that could require DPL to post collateral. To the extent that the fair value of the natural gas derivative transaction in a net loss position exceeds the unsecured credit threshold, then collateral is required to be posted in an amount equal to the amount by which the unsecured credit threshold is exceeded. The DPL obligations are standalone, without the guaranty of PHI. If DPL lost its investment grade credit rating as of December 31, 2018, DPL could have been required to post an additional amount of approximately $11 million of collateral to its natural gas counterparties.

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

13. Debt and Credit Agreements (All Registrants)

Short-Term Borrowings

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

360

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Commercial Paper
The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at December 31, 2018 and 2017:

	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,			
Commercial Paper Issuer	2018[a][b][c]	2017[a][b][c]	2018	2017	2018		2017	
Exelon Corporate	$600	$ 600	$ —	$ —	1.93	%	1.16	%
Generation	5,300	5,300	—	—	1.96	%	1.23	%
ComEd	1,000	1,000	—	—	2.14	%	1.24	%
PECO	600	600	—	—	2.24	%	1.13	%
BGE	600	600	35	77	2.18	%	1.28	%
Pepco	300	500	40	26	2.24	%	1.06	%
DPL	300	500	—	216	2.07	%	1.48	%
ACE	300	350	14	108	2.21	%	1.43	%
Total	$9,000	$ 9,450	$ 89	$ 427				

(a) Excludes $545 million and $480 million in bilateral credit facilities at December 31, 2018 and 2017, respectively, and $159 million and $179 million in credit facilities for project finance at December 31, 2018 and 2017, respectively. These credit facilities do not back Generation's commercial paper program.

(b) At December 31, 2018, excludes $135 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $33 million, $34 million, $5 million, $5 million, $5 million and $5 million, respectively. These facilities expire on October 11, 2019. These facilities are solely utilized to issue letters of credit. At December 31, 2017, excludes $128 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $34 million, $34 million, $5 million, $2 million, $2 million, and $2 million, respectively.

(c) Pepco, DPL and ACE's revolving credit facility is subject to available borrowing capacity. The borrowing capacity may be increased or decreased during the term of the facility, except that (i) the sum of the borrowing capacity must equal the total amount of the facility, and (ii) the aggregate amount of credit used at any given time by each of Pepco, DPL or ACE may not exceed $900 million or the maximum amount of short-term debt the company is permitted to have outstanding by its regulatory authorities. The total number of the borrowing reallocations may not exceed eight per year during the term of the facility.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of outstanding commercial paper does not reduce available capacity under a Registrant’s credit facility, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit facility.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2018, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit facilities:

					Available Capacity at December 31, 2018	
Borrower	Facility Type	Aggregate Bank Commitment[(a)]	Facility Draws	Outstanding Letters of Credit	Actual	To Support Additional Commercial Paper[(b)]
Exelon Corporate	Syndicated Revolver	$ 600	$ —	$ 9	$591	$ 591
Generation	Syndicated Revolver	5,300	—	1,203	4,097	4,097
Generation	Bilaterals	545	—	353	192	—
Generation	Project Finance	159	—	119	40	—
ComEd	Syndicated Revolver	1,000	—	2	998	998
PECO	Syndicated Revolver	600	—	—	600	600
BGE	Syndicated Revolver	600	—	1	599	564
Pepco	Syndicated Revolver	300	—	8	292	252
DPL	Syndicated Revolver	300	—	1	299	299
ACE	Syndicated Revolver	300	—	—	300	286
Total		$ 9,704	$ —	$ 1,696	$8,008	$ 7,687

(a) Excludes $135 million of credit facility agreements arranged at minority and community banks at Generation, ComEd, PECO, BGE, Pepco, DPL and ACE with aggregate commitments of $49 million, $33 million, $34 million, $5 million, $5 million, $5 million and $5 million, respectively. These facilities expire on October 11, 2019. These facilities are solely utilized to issue letters of credit. As of December 31, 2018, letters of credit issued under these facilities totaled $5 million and $2 million for Generation and BGE, respectively.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables present the short-term borrowings activity for Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE during 2018, 2017 and 2016.

Exelon

	2018	2017	2016
Average borrowings	$531	$823	$1,125
Maximum borrowings outstanding	1,237	2,147	3,076
Average interest rates, computed on a daily basis	2.21 %	1.32 %	0.88 %
Average interest rates, at December 31	2.15 %	1.24 %	1.12 %

Generation

	2018	2017	2016
Average borrowings	$37	$405	$536
Maximum borrowings outstanding	583	1,455	1,735
Average interest rates, computed on a daily basis	1.96 %	1.23 %	0.94 %
Average interest rates, at December 31	1.96 %	1.23 %	1.14 %

ComEd

	2018	2017	2016
Average borrowings	$154	$200	$256
Maximum borrowings outstanding	520	470	755
Average interest rates, computed on a daily basis	2.14 %	1.24 %	0.77 %
Average interest rates, at December 31	2.14 %	1.24 %	N/A

PECO

	2018	2017	2016
Average borrowings	$68	$2	$—
Maximum borrowings outstanding	350	60	—
Average interest rates, computed on a daily basis	2.24 %	1.13 %	N/A
Average interest rates, at December 31	2.24 %	1.13 %	N/A

BGE

	2018	2017	2016
Average borrowings	$65	$54	$143
Maximum borrowings outstanding	239	165	369
Average interest rates, computed on a daily basis	2.18 %	1.28 %	0.77 %
Average interest rates, computed at December 31	2.18 %	1.28 %	0.95 %

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI Corporate

	2018	2017	2016
Average borrowings	N/A	N/A	$153
Maximum borrowings outstanding	N/A	N/A	559
Average interest rates, computed on a daily basis	N/A	N/A	1.03 %
Average interest rates, computed at December 31	N/A	N/A	N/A

Pepco

	2018	2017	2016
Average borrowings	$22	$51	$4
Maximum borrowings outstanding	90	197	73
Average interest rates, computed on a daily basis	2.24%	1.06%	0.71 %
Average interest rates, computed at December 31	2.24%	1.06%	0.90 %

DPL

	2018	2017	2016
Average borrowings	$87	$40	$33
Maximum borrowings outstanding	245	216	116
Average interest rates, computed on a daily basis	2.07%	1.48%	0.68 %
Average interest rates, computed at December 31	2.07%	1.48%	N/A

ACE

	2018	2017	2016
Average borrowings	$95	$30	$—
Maximum borrowings outstanding	210	133	5
Average interest rates, computed on a daily basis	2.21%	1.43%	0.65 %
Average interest rates, computed at December 31	2.21%	1.43%	N/A

Short-Term Loan Agreements

On January 13, 2016, PHI entered into a $500 million term loan agreement, which was amended on March 28, 2016. The net proceeds of the loan were used to repay PHI's outstanding commercial paper, and for general corporate purposes. Pursuant to the loan agreement, as amended, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1%, and all indebtedness thereunder is unsecured. On March 23, 2017, the aggregate principal amount of all loans, together with any accrued but unpaid interest due under the loan agreement was fully repaid and the loan terminated. On March 23, 2017, Exelon Corporate entered into a similar type term loan for $500 million which expired on March 22, 2018. The loan agreement was renewed on March 22, 2018 and will expire on March 21, 2019. Pursuant to the loan agreement, loans made thereunder bear interest at a variable rate equal to LIBOR plus 1% and all indebtedness thereunder is unsecured. The loan agreement is reflected in Exelon's Consolidated Balance Sheet within Short-Term borrowings.

On May 23, 2018, ACE entered into two term loan agreements in the aggregate amount of $125 million, which expire on May 22, 2019. Pursuant to the term loan agreements, loans made thereunder bear interest at a variable rate equal to LIBOR plus 0.55% and all indebtedness thereunder is unsecured.

Credit Agreements

On January 5, 2016, Generation entered into a credit agreement establishing a $150 million bilateral credit facility. On January 4, 2019, the credit agreement was amended to extend its maturity from January 2019 to April 2021.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

This facility will solely be utilized by Generation to issue lines of credit. This facility does not back Generation's commercial paper program.
On April 1, 2016, the credit agreement for CENG's $100 million bilateral credit facility was amended to increase the overall facility size to $200 million, scheduled to mature in October of 2019. This facility is utilized by CENG to fund working capital and capital projects. The facility does not back Generation's commercial paper program.
On May 26, 2016, Exelon Corporate, Generation, ComEd, PECO and BGE entered into amendments to each of their respective syndicated revolving credit facilities, which extended the maturity of each of the facilities to May 26, 2021. Exelon Corporate also increased the size of its facility from $500 million to $600 million. On May 26, 2016, PHI, Pepco, DPL and ACE entered into an amendment to their Second Amended and Restated Credit Agreement dated as of August 1, 2011, which (i) extended the maturity date of the facility to May 26, 2021, (ii) removed PHI as a borrower under the facility, (iii) decreased the size of the facility from $1.5 billion to $900 million and (iv) aligned its financial covenant from debt to capitalization leverage ratio to interest coverage ratio. On May 26, 2018, each of the Registrants' respective syndicated revolving credit facilities had their maturity dates extended to May 26, 2023.
On January 9, 2017, the credit agreement for Generation's $75 million bilateral credit facility was amended and restated to increase the facility size to $100 million. On January 4, 2019, the credit agreement was amended to extend its maturity from January 2019 to March 2021. This facility will solely be used by Generation to issue letters of credit.
On March 15, 2018, the credit agreement for a Generation bilateral credit facility of $30 million was amended to increase the overall facility size to $95 million, scheduled to mature in March of 2020. This facility will solely be used by Generation to issue letters of credit.
Borrowings under Exelon Corporate’s, Generation’s, ComEd’s, PECO’s, BGE's, Pepco's, DPL's and ACE's revolving credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant’s credit rating. The adders for the prime based borrowings and LIBOR-based borrowings are presented in the following table:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Prime based borrowings	27.5	27.5	7.5	—	—	7.5	7.5	7.5
LIBOR-based borrowings	127.5	127.5	107.5	90.0	100.0	107.5	107.5	107.5

The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 90 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments. The fee varies depending upon the respective credit ratings of the borrower.
Each revolving credit agreement for Exelon, Generation, ComEd, PECO, BGE, Pepco, DPL and ACE requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2018:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2018, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
Interest coverage ratio	7.34	10.99	7.34	8.14	9.77	5.98	7.03	5.06

An event of default under Exelon, Generation, ComEd, PECO or BGE's indebtedness will not constitute an event of default under any of the others’ credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation

Table of Contents

will constitute an event of default under the Exelon Corporate credit facility. An event of default under Pepco, DPL or ACE's indebtedness will not constitute an event of default with respect to the other PHI Utilities under the PHI Utilities' combined credit facility.

The absence of a material adverse change in Exelon's or PHI’s business, property, results of operations or financial condition is not a condition to the availability of credit under any of the borrowers' credit agreement. None of the credit agreements include any rating triggers.

Variable Rate Demand Bonds

DPL has outstanding obligations in respect of Variable Rate Demand Bonds (VRDB). VRDBs are subject to repayment on the demand of the holders and, for this reason, are accounted for as short-term debt in accordance with GAAP. However, bonds submitted for purchase are remarketed by a remarketing agent on a best efforts basis. PHI expects that any bonds submitted for purchase will be remarketed successfully due to the creditworthiness of the issuer and, as applicable, the credit support, and because the remarketing resets the interest rate to the then-current market rate. The bonds may be converted to a fixed-rate, fixed-term option to establish a maturity which corresponds to the date of final maturity of the bonds. On this basis, PHI views VRDBs as a source of long-term financing. As of both December 31, 2018 and December 31, 2017, $79 million in variable rate demand bonds issued by DPL were outstanding and are included in the Long-term debt due within one year in Exelon's, PHI's and DPL's Consolidated Balance Sheet.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Long-Term Debt
The following tables present the outstanding long-term debt at the Registrants as of December 31, 2018 and 2017:
Exelon

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
First mortgage bonds[(a)]	1.70%-7.90%	2019 - 2048	16,496	15,197
Senior unsecured notes	2.45%-7.60%	2019 - 2046	11,285	11,285
Unsecured notes	2.40%-6.35%	2021 - 2048	2,900	2,600
Pollution control notes	2.50%-2.70%	2025 - 2036	435	435
Nuclear fuel procurement contracts	3.15%	2020	39	82
Notes payable and other[(b)(c)]	2.85%-8.88%	2019 - 2053	188	405
Junior subordinated notes	3.50%	2022	1,150	1,150
Long-term software licensing agreement	3.95%	2024	73	79
Unsecured Tax-Exempt Bonds	1.74%-5.40%	2024 - 2031	112	112
Medium-Terms Notes (unsecured)	7.61%-7.72%	2019 - 2027	22	26
Transition bonds	5.55%	2023	59	90
Loan Agreement	2.00%	2023	50	—
Nonrecourse debt:				
Fixed rates	2.29%-6.00%	2031 - 2037	1,253	1,331
Variable rates[(f)]	5.81%	2019 - 2024	849	865
Total long-term debt			34,911	33,657
Unamortized debt discount and premium, net			(66)	(57)
Unamortized debt issuance costs			(216)	(201)
Fair value adjustment			795	865
Long-term debt due within one year[(e)]			(1,349)	(2,088)
Long-term debt			$34,075	$32,176
Long-term debt to financing trusts[(d)]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$206	$206
Subordinated debentures to PECO Trust III	7.38%-7.50%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Total long-term debt to financing trusts			390	390
Unamortized debt issuance costs			—	(1)
Long-term debt to financing trusts			$390	$389

(a) Substantially all of ComEd’s assets other than expressly excepted property and substantially all of PECO’s, Pepco's, DPL's and ACE's assets are subject to the liens of their respective mortgage indentures.

(b) Includes capital lease obligations of $36 million and $53 million at December 31, 2018 and 2017, respectively. Lease payments of $21 million, $5 million, $1 million, $1 million, less than $1 million, and $8 million will be made in 2019, 2020, 2021, 2022, 2023, and thereafter, respectively.

(c) Includes financing related to Albany Green Energy, LLC (AGE). During the third quarter of 2017, Generation retired $228 million of its outstanding debt balance.

(d) Amounts owed to these financing trusts are recorded as Long-term debt to financing trusts within Exelon’s Consolidated Balance Sheets.

(e) In January 2019, $300 million of ComEd long-term debt due within one year was paid in full.

(f) Excludes interest on CEU Upstream nonrecourse debt, see discussion below.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
Senior unsecured notes	2.95%-7.60%	2019 - 2042	$6,019	$6,019
Pollution control notes	2.50%-2.70%	2025 - 2036	435	435
Nuclear fuel procurement contracts	3.15%	2020	39	82
Notes payable and other[(a)(b)]	2.85%-7.83%	2019 - 2024	164	223
Nonrecourse debt:				
Fixed rates	2.29%-6.00%	2031 - 2037	1,253	1,331
Variable rates[(c)]	5.81%	2019 - 2024	849	865
Total long-term debt			8,759	8,955
Unamortized debt discount and premium, net			(6)	(8)
Unamortized debt issuance costs			(51)	(60)
Fair value adjustment			91	103
Long-term debt due within one year			(906)	(346)
Long-term debt			$7,887	$8,644

(a) Includes Generation's capital lease obligations of $14 million and $18 million at December 31, 2018 and 2017, respectively. Generation will make lease payments of $7 million, $5 million, $1 million, and $1 million in 2019, 2020, 2021, and 2022, respectively. Lease payments of less than $1 million annually will be made from 2023 through expiration of the final capital lease in 2024.
(b) Includes financing related to Albany Green Energy, LLC (AGE). During the third quarter of 2017, Generation retired $228 million of its outstanding debt balance.
(c) Excludes interest on CEU Upstream nonrecourse debt, see discussion below.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd

	Rates	Maturity Date	December 31, 2018	December 31, 2017
Long-term debt				
First mortgage bonds[(a)]	2.15%-6.45%	2019 - 2048	$8,179	$7,529
Notes payable and other[(b)]	7.49%	2053	8	147
Total long-term debt			8,187	7,676
Unamortized debt discount and premium, net			(23)	(23)
Unamortized debt issuance costs			(63)	(52)
Long-term debt due within one year[(d)]			(300)	(840)
Long-term debt			$7,801	$6,761
Long-term debt to financing trust[(c)]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$206	$206
Total long-term debt to financing trusts			206	206
Unamortized debt issuance costs			(1)	(1)
Long-term debt to financing trusts			$205	$205

(a) Substantially all of ComEd's assets, other than expressly excepted property, are subject to the lien of its mortgage indenture.
(b) Includes ComEd's capital lease obligations of $8 million at both December 31, 2018 and 2017, respectively. Lease payments of less than $1 million annually will be made from 2019 through expiration at 2053.
(c) Amount owed to this financing trust is recorded as Long-term debt to financing trust within ComEd's Consolidated Balance Sheets.
(d) In January 2019, the $300 million balance was paid in full.

PECO

	Rates	Maturity Date	December 31, 2018	December 31, 2017
Long-term debt				
First mortgage bonds[(a)]	1.70%-5.95%	2021 - 2048	$3,075	$2,925
Loan Agreement	2.00%	2023	50	0
Total long-term debt			3,125	2,925
Unamortized debt discount and premium, net			(18)	(5)
Unamortized debt issuance costs			(23)	(17)
Long-term debt due within one year			—	(500)
Long-term debt			$3,084	$2,403
Long-term debt to financing trusts[(b)]				
Subordinated debentures to PECO Trust III	7.38%-7.50%	2028	$81	$81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long-term debt to financing trusts			$184	$184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Amounts owed to this financing trust are recorded as Long-term debt to financing trusts within PECO's Consolidated Balance Sheets.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

BGE

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
Unsecured notes	2.40%-6.35%	2021 - 2048	2,900	2,600
Total long-term debt			2,900	2,600
Unamortized debt discount and premium, net			(6)	(6)
Unamortized debt issuance costs			(18)	(17)
Long-term debt			$2,876	$2,577

PHI

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
First mortgage bonds[(a)]	1.81%-7.90%	2021 - 2048	$5,242	$4,743
Senior unsecured notes	7.45%	2032	185	185
Unsecured Tax-Exempt Bonds	1.74%-5.40%	2024 - 2031	112	112
Medium-terms notes (unsecured)	7.61%-7.72%	2019 - 2027	22	26
Transition bonds[(b)]	5.55%	2023	59	90
Notes payable and other [(c)]	7.28%-8.88%	2019 - 2022	16	33
Total long-term debt			5,636	5,189
Unamortized debt discount and premium, net			4	5
Unamortized debt issuance costs			(14)	(6)
Fair value adjustment			633	686
Long-term debt due within one year			(125)	(396)
Long-term debt			$6,134	$5,478

(a) Substantially all of Pepco's, DPL's, and ACE's assets are subject to the lien of its respective mortgage indenture.
(b) Transition bonds are recorded as part of Long-term debt within ACE's Consolidated Balance Sheets.
(c) Includes Pepco's capital lease obligations of $14 million and $27 million at December 31, 2018 and 2017, respectively.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
First mortgage bonds[a]	3.05%-7.90%	2022 - 2048	$2,735	$2,535
Notes payable and other[b]	7.28%-8.88%	2019 - 2022	16	35
Total long-term debt			2,751	2,570
Unamortized debt discount and premium, net			2	2
Unamortized debt issuance costs			(34)	(32)
Long-term debt due within one year			(15)	(19)
Long-term debt			$2,704	$2,521

(a) Substantially all of Pepco's assets are subject to the lien of its respective mortgage indenture.
(b) Includes capital lease obligations of $14 million and $27 million at December 31, 2018 and 2017, respectively. Lease payments of $14 million will be made in 2019.

DPL

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
First mortgage bonds[a]	1.81%-4.27%	2023 - 2048	$1,370	$1,171
Unsecured Tax-Exempt Bonds	1.74%-5.40%	2024 - 2031	112	112
Medium-terms notes (unsecured)	7.61%-7.72%	2019 - 2027	22	26
Total long-term debt			1,504	1,309
Unamortized debt discount and premium, net			2	2
Unamortized debt issuance costs			(12)	(11)
Long-term debt due within one year			(91)	(83)
Long-term debt			$1,403	$1,217

(a) Substantially all of DPL's assets are subject to the lien of its respective mortgage indenture.

ACE

	Rates	Maturity Date	December 31, 2018	2017
Long-term debt				
First mortgage bonds[a]	3.38%-6.80%	2021 - 2036	$1,137	$1,037
Transition bonds[b]	5.55%	2023	59	90
Total long-term debt			1,196	1,127
Unamortized debt discount and premium, net			(1)	(1)
Unamortized debt issuance costs			(7)	(5)
Long-term debt due within one year			(18)	(281)
Long-term debt			$1,170	$840

(a) Substantially all of ACE's assets are subject to the lien of its respective mortgage indenture.
(b) Maturities of ACE's Transition Bonds outstanding at December 31, 2018 are $18 million in 2019, $20 million in 2020 and $21 million in 2021.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Long-term debt maturities at Exelon, Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE in the periods 2019 through 2023 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
2019	$1,349	$ 906	$300	$—	$—	$125	$15	$91	$18
2020	3,528	2,108	500	—	—	20	—	—	20
2021	1,511	1	350	300	300	261	1	—	260
2022	3,084	1,024	—	350	250	310	310	—	—
2023	850	—	—	50	300	500	—	500	—
Thereafter	24,979 (a)	4,720	7,243 (b)	2,609 (c)	2,050	4,420	2,425	913	898
Total	$35,301	$ 8,759	$8,393	$3,309	$2,900	$5,636	$2,751	$1,504	$1,196

____
(a) Includes $390 million due to ComEd and PECO financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.

Junior Subordinated Notes

In June 2014, Exelon issued $1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of $50.00 per unit. Each equity unit represented an undivided beneficial ownership interest in Exelon's $1.15 billion of 2.50% junior subordinated notes due in 2024 ("2024 notes") and a forward equity purchase contract. As contemplated in the June 2014 equity unit structure, in April 2017, Exelon completed the remarketing of the 2024 notes into $1.15 billion of 3.497% junior subordinated notes due in 2022 ("Remarketing"). Exelon conducted the Remarketing on behalf of the holders of equity units and did not directly receive any proceeds therefrom. Instead, the former holders of the 2024 notes used debt remarketing proceeds towards settling the forward equity purchase contract with Exelon on June 1, 2017. Exelon issued approximately 33 million shares of common stock from treasury stock and received $1.15 billion upon settlement of the forward equity purchase contract. When reissuing treasury stock Exelon uses the average price paid to repurchase shares to calculate a gain or loss on issuance and records gains or losses directly to retained earnings. A loss on reissuance of treasury shares of $1.05 billion was recorded to retained earnings as of December 31, 2017. See Note 20 — Earnings Per Share for additional information on the issuance of common stock.

Nonrecourse Debt

Exelon and Generation have issued nonrecourse debt financing, in which approximately $2.9 billion of generating assets have been pledged as collateral at December 31, 2018. 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 lives.

Denver Airport. In June 2011, Generation entered into a 20-year, $7 million solar loan agreement to finance a solar construction project in Denver, Colorado. The agreement is scheduled to mature on June 30, 2031. The agreement bears interest at a fixed rate of 5.50% annually with interest payable annually. As of December 31, 2018, $6 million was outstanding.

CEU Upstream. In July 2011, CEU Holdings, LLC, a wholly owned subsidiary of Generation, entered into a 5-year reserve based lending agreement (RBL) associated with certain Upstream oil and gas properties. The lenders do not have recourse against Exelon or Generation in the event of default pursuant to the RBL. Borrowings under this arrangement are secured by the assets and equity of CEU Holdings.

In December 2016, substantially all of the Upstream natural gas and oil exploration and production assets were sold for $37 million. The proceeds were used to reduce the debt balance by $31 million. The remaining proceeds

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

of $6 million were being held in escrow. In addition, during 2016, $15 million of the debt was repaid using CEU Holding's cash, resulting in an outstanding debt balance of $22 million at December 31, 2016. During 2017, additional assets were sold for $1 million and the remaining $6 million in escrow was released and applied to the debt balance resulting in an outstanding amount of $15 million at December 31, 2017. Upon final resolution, CEU Holdings will be released of its obligations regardless of the amount of asset sale proceeds received. The ultimate resolution of this matter has no direct effect on any Exelon or Generation credit facilities or other debt of an Exelon entity. At December 31, 2018, the outstanding debt balance of $15 million was classified within Long term debt due within one year in Exelon's and Generation's Consolidated Balance Sheets. See Note 5 — Mergers, Acquisitions and Dispositions and Note 7 — Impairment of Long-Lived Assets and Intangibles for additional information.

Holyoke Solar Cooperative. In October 2011, Generation entered into a 20-year, $11 million solar loan agreement related to a solar construction project in Holyoke, Massachusetts. The agreement is scheduled to mature on December 2031. The agreement bears interest at a fixed rate of 5.25% annually with interest payable monthly. As of December 31, 2018, $8 million was outstanding.

Antelope Valley Solar Ranch One. In December 2011, the DOE Loan Programs Office issued a guarantee for up to $646 million for a nonrecourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project became fully operational in 2014. The loan will mature on January 5, 2037. Interest rates on the loan were fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity. The advances were completed as of December 31, 2015 and the outstanding loan balance will bear interest at an average blended interest rate of 2.82%. As of December 31, 2018, $508 million was outstanding. In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2018, Generation had $38 million in letters of credit outstanding related to the project. In 2017, Generation's interests in Antelope Valley were also contributed to and are pledged as collateral for the EGR IV financing structure referenced below.

Continental Wind. In September 2013, Continental Wind, LLC (Continental Wind), an indirect subsidiary of Exelon and Generation, completed the issuance and sale of $613 million senior secured notes. Continental Wind owns and operates a portfolio of wind farms in Idaho, Kansas, Michigan, Oregon, New Mexico and Texas with a total net capacity of 667MW. The net proceeds were distributed to Generation for its general business purposes. The notes are scheduled to mature on February 28, 2033. The notes bear interest at a fixed rate of 6.00% with interest payable semi-annually. As of December 31, 2018, $479 million was outstanding.

In addition, Continental Wind entered into a $131 million letter of credit facility and $10 million working capital revolver facility. Continental Wind has issued letters of credit to satisfy certain of its credit support and security obligations. As of December 31, 2018, the Continental Wind letter of credit facility had $114 million in letters of credit outstanding related to the project.

In 2017, Generation's interests in Continental Wind were contributed to EGRP. Refer to Note 2 - Variable Interest Entities for additional information on EGRP.

ExGen Texas Power. In September 2014, EGTP, an indirect subsidiary of Exelon and Generation, issued $675 million aggregate principal amount of a nonrecourse senior secured term loan. The net proceeds were distributed to Generation for general business purposes. The loan was scheduled to mature on September 18, 2021. In addition to the financing, EGTP entered into various interest rate swaps with an initial notional amount of approximately $505 million at an interest rate of 2.34% to hedge a portion of the interest rate exposure in connection with this financing, as required by the debt covenants.

On May 2, 2017, as a result of the negative impacts of certain market conditions and the seasonality of its cash flows, EGTP entered into a consent agreement with its lenders, which permitted EGTP to draw on its revolving credit facility and initiate an orderly sales process of its assets. On November 7, 2017, the debtors filed voluntary petitions for relief under Chapter 11 of Title 11 of the United States Code in the United States Bankruptcy Court for the District of

Delaware. As a result, Exelon and Generation deconsolidated the nonrecourse senior secured term loan, the revolving credit facility, and the interest rate swaps from their consolidated financial statements as of December 31, 2017. Due to their nonrecourse nature, these borrowings are secured solely by the assets of EGTP and its subsidiaries.

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The Chapter 11 bankruptcy proceedings were finalized on April 17, 2018, resulting in the ownership of EGTP assets (other than the Handley Generating Station) being transferred to EGTP's lenders. See Note 5 — Mergers, Acquisitions and Dispositions for additional information on EGTP.

Renewable Power Generation. In March 2016, RPG, an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for paydown of long term debt obligations at Sacramento PV Energy and Constellation Solar Horizons and for general business purposes. The loan is scheduled to mature on March 31, 2035. The term loan bears interest at a fixed rate of 4.11% payable semi-annually. As of December 31, 2018, $115 million was outstanding.

In 2017, Generation’s interests in Renewable Power Generation were contributed to EGRP. Refer to Note 2 - Variable interest Entities for additional information on EGRP.

SolGen. In September 2016, SolGen, LLC (SolGen), an indirect subsidiary of Exelon and Generation, issued $150 million aggregate principal amount of a nonrecourse senior secured notes. The net proceeds were distributed to Generation for general business purposes. The loan is scheduled to mature on September 30, 2036. The term loan bears interest at a fixed rate of 3.93% payable semi-annually. As of December 31, 2018, $137 million was outstanding. In 2017, Generation’s interests in SolGen were also contributed to and are pledged as collateral for the EGR IV financing structure referenced below.

ExGen Renewables IV. In November 2017, EGR IV, an indirect subsidiary of Exelon and Generation, entered into an $850 million nonrecourse senior secured term loan credit facility agreement. Generation’s interests in EGRP, Antelope Valley, SolGen, and Albany Green Energy were all contributed to and are pledged as collateral for this financing. The net proceeds of $785 million, after the initial funding of $50 million for debt service and liquidity reserves as well as deductions for original discount and estimated costs, fees and expenses incurred in connection with the execution and delivery of the credit facility agreement, were distributed to Generation for general corporate purposes. The $50 million of debt service and liquidity reserves was treated as restricted cash in Exelon’s and Generation’s Consolidated Balance Sheets and Consolidated Statements of Cash Flows. The loan is scheduled to mature on November 28, 2024. The term loan bears interest at a variable rate equal to LIBOR + 3%, subject to a 1% LIBOR floor with interest payable quarterly. As of December 31, 2018, $834 million was outstanding. In addition to the financing, EGR IV entered into interest rate swaps with an initial notional amount of $636 million at an interest rate of 2.32% to manage a portion of the interest rate exposure in connection with the financing. See Note 2 - Variable interest Entities for additional information on EGRP.

14. Income Taxes (All Registrants)

Corporate Tax Reform (All Registrants)

On December 22, 2017, President Trump signed the TCJA into law. The TCJA makes many significant changes to the Internal Revenue Code, including, but not limited to, (1) reducing the U.S. federal corporate tax rate from 35% to 21%; (2) creating a 30% limitation on deductible interest expense (not applicable to regulated utilities); (3) allowing 100% expensing for the cost of qualified property (not applicable to regulated utilities); (4) eliminating the domestic production activities deduction; (5) eliminating the corporate alternative minimum tax and changing how existing alternative minimum tax credits can be realized; and (6) changing rules related to uses and limitations of net operating loss carryforwards created in tax years beginning after December 31, 2017. The most significant change that impacts the Registrants is the reduction of the corporate federal income tax rate from 35% to 21% beginning January 1, 2018.

Pursuant to the enactment of the TCJA, the Registrants remeasured their existing deferred income tax balances as of December 31, 2017 to reflect the decrease in the corporate income tax rate from 35% to 21%, which resulted in a material decrease to their net deferred income tax liability balances as shown in the table below. Generation recorded a corresponding net decrease to income tax expense, while the Utility Registrants recorded corresponding regulatory liabilities or assets to the extent such amounts are probable of settlement or recovery through customer rates and an adjustment to income tax expense for all other amounts. The amount and timing of potential settlements of the established net regulatory liabilities are determined by the Utility Registrants’ respective rate regulators, subject to certain IRS “normalization” rules. See Note 4 — Regulatory Matters for additional information regarding settlements for passing back of TCJA income tax savings benefits to customers.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The Registrants assessed the applicable provisions in the TCJA and recorded the associated impacts as of December 31, 2017. The Registrants recorded provisional income tax amounts as of December 31, 2017, as allowed under SAB 118 issued by the SEC in December 2017, for changes pursuant to the TCJA related to depreciation because the impacts could not be finalized upon issuance of the Registrants' financial statements, but for which reasonable estimates could be determined.

On August 3, 2018, the U.S. Department of Treasury, in conjunction with the IRS, released proposed regulations clarifying the immediate expensing provisions enacted by the TCJA, specifically that regulated utility property acquired after September 27, 2017, and placed in service by December 31, 2017, qualifies for 100% expensing. Until the proposed regulations are finalized, taxpayers may rely on the proposed regulations for tax years ending after September 28, 2017. The Registrants recorded the impact of these proposed regulations and the adjustment was immaterial.

While the Registrants have recorded the impacts of the TCJA based on their interpretation of the provisions as enacted, it is expected the U.S. Department of Treasury and the IRS will issue additional interpretative guidance in the future that could result in changes to previously finalized provisions. At this time, many of the states in which Exelon does business have issued guidance regarding TCJA and the impact was not material.

The one-time impacts recorded by the Registrants to remeasure their deferred income tax balances at the 21% corporate federal income tax rate as of December 31, 2017 are presented below:

	Exelon[b]	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Net Decrease to Deferred Income Tax Liability Balances	$8,624	$1,895	$2,819	$1,407	$1,120	$1,944	$968	$540	$456

	Exelon	Generation	ComEd	PECO[c]	BGE	Successor PHI	Pepco	DPL	ACE
Net Regulatory Liability Recorded[a]	$7,315	N/A	$2,818	$1,394	$1,124	$1,979	$976	$545	$458

	Exelon[b]	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Net Deferred Income Tax Benefit/(Expense) Recorded	$1,309	$1,895	$1	$13	$(4)	$(35)	$(8)	$(5)	$(2)

____

(a) Reflects the net regulatory liabilities recorded on a pre-tax basis before taking into consideration the income tax benefits associated with the ultimate settlement with customers.

(b) Amounts do not sum across due to deferred tax adjustments recorded at the Exelon Corporation parent company, primarily related to certain employee compensation plans.

(c) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO remained in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA.

The net regulatory liabilities above include (1) amounts subject to IRS "normalization" rules that are required to be passed back to customers generally over the remaining useful life of the underlying assets giving rise to the associated deferred income taxes, and (2) amounts for which the timing of settlement with customers is subject to determinations by the rate regulators. The table below sets forth the Registrants' estimated categorization of their net regulatory liabilities as of December 31, 2017. The amounts in the table below are shown on an after-tax basis reflecting future net cash outflows after taking into consideration the income tax benefits associated with the ultimate settlement with customers.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Exelon	ComEd	PECO[(a)]	BGE	Successor PHI	PEPCO	DPL	ACE
Subject to IRS Normalization Rules	$3,040	$1,400	$533	$459	$648	$299	$195	$153
Subject to Rate Regulator Determination	1,694	573	43	324	754	391	194	170
Net Regulatory Liabilities	$4,734	$1,973	$576	$783	$1,402	$690	$389	$323

(a) Given the regulatory treatment of income tax benefits related to electric and gas distribution repairs, PECO was in an overall net regulatory asset position as of December 31, 2017 after recording the impacts related to the TCJA. As a result, the amount of customer benefits resulting from the TCJA subject to the discretion of PECO's rate regulators are lower relative to the other Utility Registrants.

The net regulatory liability amounts subject to the IRS normalization rules generally relate to property, plant and equipment with remaining useful lives ranging from 30 to 40 years across the Utility Registrants. For the other amounts, rate regulators could require the passing back of amounts to customers over shorter time frames. See Note 4 - Regulatory Matters for additional information.

Components of Income Tax Expense or Benefit

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2018	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$226	$ 337	$ (63)	$ 11	$(5)	$ (4)	$ 28	$(3)	$(14)
Deferred	(98)	(347)	145	10	47	24	(21)	13	18
Investment tax credit amortization	(24)	(21)	(2)	—	—	(1)	—	—	—
State									
Current	(1)	6	(29)	1	—	7	—	—	—
Deferred	17	(83)	117	(16)	32	9	6	12	8
Total	$120	$ (108)	$ 168	$ 6	$74	$ 35	$ 13	$22	$12

For the Year Ended December 31, 2017[(a)]	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Included in operations:									
Federal									
Current	$194	$ 584	$(191)	$71	$74	$ (60)	$(20)	$(24)	$(12)
Deferred	(471)	(2,005)	523	28	101	250	114	82	34
Investment tax credit amortization	(25)	(21)	(2)	—	(1)	(1)	—	—	—
State									
Current	14	65	(49)	14	(5)	(4)	(2)	—	—
Deferred	162	1	136	(9)	49	32	13	13	4
Total	$(126)	$ (1,376)	$417	$104	$218	$ 217	$105	$71	$26

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Year Ended December 31, 2016[(a)]								Successor March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE	PHI	PHI
Included in operations:										
Federal										
Current	$60	$ 513	$(135)	$63	$51	$(118)	$(88)	$(26)	$ (281)	$ —
Deferred	600	(254)	379	72	88	136	97	22	283	10
Investment tax credit amortization	(24)	(20)	(2)	—	(1)	—	—	—	(1)	—
State										
Current	39	45	(4)	9	5	7	1	—	(11)	—
Deferred	78	(2)	63	5	31	16	12	—	13	7
Total	$753	$ 282	$301	$149	$174	$41	$22	$(4)	$ 3	$ 17

(a) Exelon retrospectively adopted the new standard Revenue from Contracts with Customers. The standard was adopted as of January 1, 2018. Components of income tax expense or benefit are recast to reflect the impact of the new standard.

Rate Reconciliation

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

	For the Year Ended December 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	0.6	(16.6)	8.3	(2.6)	6.6	3.0	2.2	6.7	7.4
Qualified NDT fund income	(1.9)	(11.8)	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(6.5)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.3)	(0.4)
Plant basis differences	(3.5)	—	(0.2)	(14.1)	(1.3)	(1.6)	(2.7)	(0.3)	(0.5)
Production tax credits and other credits	(2.2)	(13.5)	—	—	—	—	—	—	—
Noncontrolling interests	(1.0)	(6.1)	—	—	—	—	—	—	—
Excess deferred tax amortization	(8.3)	—	(9.1)	(3.2)	(8.0)	(14.5)	(14.8)	(12.0)	(14.9)
Tax Cuts and Jobs Act of 2017	0.9	2.7	(0.1)	—	—	0.1	—	—	—
Other	1.0	1.3	0.5	0.3	0.9	0.3	0.2	0.4	1.2
Effective income tax rate	5.4 %	(29.5)%	20.2 %	1.3 %	19.1 %	8.1 %	5.8 %	15.5 %	13.8 %

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Year Ended December 31, 2017[a]								
	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:									
State income taxes, net of Federal income tax benefit	2.3	2.9	5.7	0.6	5.4	4.8	3.2	5.4	5.6
Qualified NDT fund income	3.8	9.9	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(0.9)	(2.1)	(0.2)	(0.1)	(0.1)	(0.2)	(0.1)	(0.2)	(0.4)
Plant basis differences[b]	(1.7)	—	0.3	(13.8)	0.1	1.1	(0.4)	2.0	3.6
Production tax credits and other credits	(1.8)	(4.7)	—	—	—	—	—	—	—
Like-kind exchange	(1.2)	—	1.3	—	—	—	—	—	—
Merger expenses	(3.6)	(1.2)	—	—	—	(9.5)	(6.3)	(7.8)	(19.8)
FitzPatrick bargain purchase gain	(2.2)	(5.6)	—	—	—	—	—	—	—
Tax Cuts and Jobs Act of 2017[c]	(33.1)	(128.3)	0.1	(2.3)	0.9	6.4	2.7	2.5	1.6
Other	0.1	(0.5)	0.2	(0.1)	0.2	(0.1)	(0.2)	0.1	(0.4)
Effective income tax rate	(3.3)%	(94.6)%	42.4 %	19.3 %	41.5 %	37.5 %	33.9 %	37.0 %	25.2 %

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	For the Year Ended December 31, 2016[a]								Successor March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016
	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL [d]	ACE [d]	PHI [d]	PHI
U.S. Federal statutory rate	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %	35.0 %
Increase (decrease) due to:										
State income taxes, net of Federal income tax benefit [e]	3.3	3.2	5.6	1.3	5.0	15.7	52.7	6.2	5.8	11.9
Qualified NDT fund income	3.4	7.9	—	—	—	—	—	—	—	—
Amortization of investment tax credit, including deferred taxes on basis difference	(1.2)	(2.3)	(0.3)	(0.1)	(0.1)	(0.2)	(3.7)	0.8	1.4	(0.9)
Plant basis differences	(4.9)	—	(0.6)	(9.6)	(2.7)	(22.8)	(25.5)	10.3	39.0	(13.5)
Production tax credits and other credits	(3.6)	(8.3)	—	—	—	—	—	—	—	—
Noncontrolling interests	(0.2)	(0.6)	—	—	—	—	—	—	—	—
Statute of limitations expiration	(0.4)	(1.7)	—	—	—	—	—	—	—	—
Penalties	1.9	—	4.5	—	—	—	—	—	(0.7)	—
Merger Expenses	5.6	1.1	—	—	—	23.5	112.9	(44.9)	(89.0)	11.1
Other [f]	(0.7)	(1.4)	0.1	(1.2)	—	(1.8)	(2.2)	1.3	3.3	3.6
Effective income tax rate	38.2 %	32.9 %	44.3 %	25.4 %	37.2 %	49.4 %	169.2 %	8.7 %	(5.2)%	47.2 %

(a) Exelon retrospectively adopted the new standard Revenue from Contracts with Customers. The standard was adopted as of January 1, 2018. The effective income tax rates are recast to reflect the impact of the new standard.

(b) Includes the charges related to the transmission-related income tax regulatory asset for Exelon, ComEd, BGE, PHI, Pepco, DPL and ACE of $35 million, $3 million, $5 million, $27 million, $14 million, $6 million and $7 million, respectively. See Note 4 - Regulatory Matters for additional information.

(c) Included are impacts for TCJA other than the corporate rate change, including revisions further limiting tax deductions for compensation of certain highest paid executives, the write-off of foreign tax credit carryforwards, and loss of a 2015 domestic production activities deduction due to an NOL carryback.

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

(e) Includes a remeasurement of uncertain state income tax positions for Pepco and DPL.

(f) At PECO, includes a cumulative adjustment related to an anticipated gas repairs tax return accounting method change. The method change request was filed and accepted in 2017. No change to the results recorded as of December 31, 2016.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Tax Differences and Carryforwards

The tax effects of temporary differences and carryforwards, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2018 and 2017 are presented below:

	As of December 31, 2018								
	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Plant basis differences	$(12,533)	$(2,495)	$(4,059)	$(1,862)	$(1,399)	$(2,577)	$(1,148)	$(743)	$(645)
Accrual based contracts	117	(44)	—	—	—	161	—	—	—
Derivatives and other financial instruments	89	35	69	—	—	3	—	—	—
Deferred pension and postretirement obligation	1,435	(188)	(255)	(26)	(26)	(102)	(78)	(46)	(14)
Nuclear decommissioning activities	(351)	(351)	—	—	—	—	—	—	—
Deferred debt refinancing costs	234	23	(7)	—	(3)	187	(4)	(2)	(1)
Regulatory assets and liabilities	(749)	—	300	(129)	172	(90)	58	96	83
Tax loss carryforward	237	78	—	18	25	96	12	52	26
Tax credit carryforward	811	816	—	—	—	—	—	—	—
Investment in partnerships	(797)	(775)	—	—	—	—	—	—	—
Other, net	934	239	151	67	12	196	98	17	19
Deferred income tax liabilities (net)	$(10,573)	$(2,662)	$(3,801)	$(1,932)	$(1,219)	$(2,126)	$(1,062)	$(626)	$(532)
Unamortized investment tax credits	(724)	(700)	(12)	(1)	(3)	(8)	(2)	(2)	(3)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(11,297)	$(3,362)	$(3,813)	$(1,933)	$(1,222)	$(2,134)	$(1,064)	$(628)	$(535)

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	As of December 31, 2017 [(a)]								
	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Plant basis differences	$(12,490)	$(2,819)	$(3,825)	$(1,762)	$(1,368)	$(2,521)	$(1,152)	$(717)	$(607)
Accrual based contracts	150	(66)	—	—	—	216	—	—	—
Derivatives and other financial instruments	(85)	(66)	(2)	—	—	3	—	—	—
Deferred pension and postretirement obligation	1,463	(205)	(285)	(15)	(29)	(130)	(78)	(51)	(18)
Nuclear decommissioning activities	(553)	(553)	—	—	—	—	—	—	—
Deferred debt refinancing costs	217	26	(8)	(1)	(3)	203	(4)	(2)	(1)
Regulatory assets and liabilities	(688)	—	489	(90)	136	(184)	39	88	86
Tax loss carryforward	344	76	33	9	11	156	40	68	35
Tax credit carryforward	861	868	1	—	—	6	—	—	—
Investment in partnerships	(434)	(416)	—	—	—	—	—	—	—
Other, net	746	78	141	71	13	193	94	14	16
Deferred income tax liabilities (net)	$(10,469)	$(3,077)	$(3,456)	$(1,788)	$(1,240)	$(2,058)	$(1,061)	$(600)	$(489)
Unamortized investment tax credits	(732)	(705)	(13)	(1)	(4)	(8)	(2)	(3)	(4)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(11,201)	$(3,782)	$(3,469)	$(1,789)	$(1,244)	$(2,066)	$(1,063)	$(603)	$(493)

____
(a) Includes remeasurement impacts related to the TCJA.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2018:

	Exelon	Generation	ComEd	PECO	BGE	Successor PHI	Pepco	DPL	ACE
Federal									
Federal general business credits carryforwards	811 [(a)]	816	—	—	—	—	—	—	—
State									
State net operating losses	4,103 [(b)]	1,544 [(b)]	—	224 [(c)]	395 [(d)]	1,492 [(e)]	192 [(f)]	772 [(g)]	365 [(h)]
Deferred taxes on state tax attributes (net)	272	104	—	18	26	102	12	52	26
Valuation allowance on state tax attributes	35	26	—	—	1	6	—	—	—

____

(a) Exelon's federal general business credit carryforwards will begin expiring in 2033.
(b) Exelon's and Generation's state net operating losses and credit carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2019.
(c) PECO's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2031.
(d) BGE's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2026.
(e) PHI's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2036.
(f) Pepco's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2033.
(g) DPL's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2030.
(h) ACE's state net operating loss carryforwards, which are presented on a post-apportioned basis, will begin expiring in 2031.

Tabular Reconciliation of Unrecognized Tax Benefits

The following tables provide a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2018, 2017 and 2016:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unrecognized tax benefits at January 1, 2018	$ 743	$ 468	$ 2	$ —	$ 120	$ 125	$ 59	$ 21	$ 14
Change to positions that only affect timing	15	15	—	—	—	—	—	—	—
Increases based on tax positions prior to 2018	30	21	—	—	—	8	7	1	—
Decreases based on tax positions prior to 2018	(251)	(36)	—	—	(120)	(88)	(66)	(22)	—
Decrease from settlements with taxing authorities	(53)	(53)	—	—	—	—	—	—	—
Decreases from expiration of statute of limitations	(7)	(7)	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2018	$ 477	$ 408	$ 2	$ —	$ —	$ 45	$ —	$ —	$ 14

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unrecognized tax benefits at January 1, 2017	$ 916	$ 490	$ (12)	$ —	$ 120	$ 172	$ 80	$ 37	$ 22
Increases based on tax positions prior to 2017	28	—	14	—	—	14	—	—	14
Decreases based on tax positions prior to 2017	(196)	(17)	—	—	—	(61)	(21)	(16)	(22)

Decrease from settlements with taxing authorities	(5)	(5)	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2017	$ 743	$ 468	$ 2	$ —	$ 120	$ 125	$ 59	$ 21	$ 14

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Unrecognized tax benefits at January 1, 2016	$1,078	$ 534	$ 142	$ —	$120	$22	$ 8	$ 3	$ —
Merger balance transfer	22	5	—	—	—	(5)	—	—	—
Increases based on tax positions related to 2016	108	10	—	—	—	59	21	16	22
Change to positions that only affect timing	(332)	(12)	(154)	—	—	—	—	—	—
Increases based on tax positions prior to 2016	88	—	—	—	—	96	51	18	—
Decreases based on tax positions prior to 2016	(21)	(20)	—	—	—	—	—	—	—
Decreases from settlements with taxing authorities	(27)	(27)	—	—	—	—	—	—	—
Unrecognized tax benefits at December 31, 2016	$916	$ 490	$ (12)	$ —	$120	$172	$ 80	$ 37	$ 22

As a result of a court decision issued in July 2018 to an unrelated taxpayer, Exelon's and Generation's unrecognized federal and state tax benefits increased in the third quarter of 2018 by approximately $71 million. Approximately $20 million of this increase impacted Exelon's and Generation's effective tax rate and resulted in a charge to earnings in the third quarter of 2018. Exelon's and Generation's unrecognized federal and state tax benefits decreased in the fourth quarter of 2018 by approximately $90 million due to the settlement of a federal audit issue with IRS Appeals. The recognition of these tax benefits decreased the effective tax rate at Exelon and Generation resulting in an income tax benefit of approximately $9 million.

In the fourth quarter of 2018, Exelon, Generation, BGE, PHI, Pepco, and DPL decreased their unrecognized state tax benefits by $241 million, $33 million, $120 million, $88 million, $66 million, and $22 million, respectively, due to the receipt of favorable guidance with respect to the deductibility of certain depreciable fixed assets. The recognition of these tax benefits decreased the effective tax rate at Exelon and Generation resulting in an income tax benefit of approximately $26 million. The recognition of the tax benefits related to BGE, PHI, Pepco, and DPL was offset by corresponding regulatory liabilities and that portion had no immediate impact to their effective tax rate.

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

Exelon reduced the liability related to the uncertain tax position associated with the like-kind exchange in the second quarter of 2017.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon, Generation, ComEd and PHI have $463 million, $408 million, $2 million and $31 million, respectively, of unrecognized tax benefits at December 31, 2018 that, if recognized, would decrease the effective tax rate. PHI has $21 million of unrecognized state tax benefits at December 31, 2018 that, if recognized, $14 million would be in the form of a net operating loss carryforward, which is expected to require a full valuation allowance based on present circumstances. PHI and ACE have $14 million of unrecognized tax benefits at December 31, 2018 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Exelon, Generation, ComEd and PHI had $523 million, $461 million, $2 million and $32 million, respectively, of unrecognized tax benefits at December 31, 2017 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco, DPL, and ACE have $120 million, $94 million, $59 million, $21 million and $14 million of unrecognized tax benefits at December 31, 2017 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon, Generation, PHI, Pepco, DPL, and ACE had $633 million, $483 million, $93 million, $21 million, $16 million, and $22 million, respectively, of unrecognized tax benefits at December 31, 2016 that, if recognized, would decrease the effective tax rate. BGE, PHI, Pepco and DPL had $120 million, $80 million, $59 million, and $21 million of unrecognized tax benefits at December 31, 2016 that, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Unrecognized tax benefits that if recognized would affect only the timing of tax payments

There are no unrecognized tax benefits as of December 31, 2018 that affect only the timing of tax payments.

Exelon and Generation had $7 million of unrecognized tax benefits at December 31, 2017 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

Exelon, Generation and ComEd had $83 million, $7 million and $(12) million of unrecognized tax benefits at December 31, 2016 for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits.

The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

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

Like-Kind Exchange

As of December 31, 2018, Exelon and ComEd have approximately $33 million and $2 million, respectively, of unrecognized federal and state income tax benefits related to the like-kind exchange litigation described further below. If Exelon does not appeal the October 2018 U.S. Court of Appeals for the Seventh Circuit's decision to the U.S. Supreme Court, Exelon's and ComEd's unrecognized tax benefits will decrease in the first quarter of 2019. See below for further details.

Settlement of Income Tax Audits, Refund Claims, and Litigation

As of December 31, 2018, Exelon, Generation, PHI and ACE have approximately $425 million, $411 million, $14 million, and $14 million respectively, of unrecognized federal and state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, refund claims, and the outcomes of pending court cases. Of the above unrecognized tax benefits, Exelon and Generation have $411 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefit related to PHI and ACE, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

Total amounts of interest and penalties recognized

The following tables represent the net interest and penalties receivable (payable), including interest and penalties related to tax positions reflected in the Registrants' Consolidated Balance Sheets.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2018	$ 236	$ (2)	$ 4	$ —	$ —	$ 1	$ —	$ —	$ —
December 31, 2017	233	(3)	4	—	—	2	—	—	—

Net penalties payable as of	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
December 31, 2018	$ (17)	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2017	(17)	—	—	—	—	—	—	—	—

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following tables set forth the net interest and penalty expense, including interest and penalties related to tax positions, recognized in Interest expense, net and Other, net in Other income and deductions in the Registrants' Consolidated Statements of Operations and Comprehensive Income.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2018	$ (3)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2017	37	(1)	11	—	—	—	—	—
December 31, 2016	165	(13)	117	—	—	6	—	(1)

Net penalty expense (income) for the years ended	Exelon	Generation	ComEd	PECO	BGE	Pepco	DPL	ACE
December 31, 2018	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —
December 31, 2017	(2)	—	—	—	—	—	—	—
December 31, 2016	106	—	86	—	—	—	—	—

PHI	Successor			Predecessor
	December 31, 2018	December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
Net interest expense	$ —	$ —	$ (2)	$ —

Description of tax years open to assessment by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated federal income tax returns	1999, 2001-2017
PHI Holdings and subsidiaries consolidated federal income tax returns	2013, 2015-2016
Exelon and subsidiaries Illinois unitary income tax returns	2010-2017
Constellation combined New York corporate income tax returns	2010-March 2012
Exelon combined New York corporate income tax returns	2011-2017
Exelon New Jersey corporate income tax returns	2013-2017
Exelon Pennsylvania corporate net income tax returns	2011-2017
PECO Pennsylvania separate company returns	2015-2017
DPL Delaware separate company returns	Same as federal
ACE New Jersey separate company returns	2014-2017
Exelon and subsidiaries District of Columbia corporate income tax returns	2015-2017
PHI Holdings and subsidiaries District of Columbia corporate income tax returns	2015-2016
Various separate company Maryland corporate net income tax returns	Same as federal

Other Tax Matters

Like-Kind Exchange

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately $1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. As previously disclosed, Exelon terminated its investment in one of the leases in 2014 and the remaining two leases were terminated in 2016.

The IRS asserted that the Exelon purchase and leaseback transaction was substantially similar to a leasing transaction, known as a SILO, which is a listed transaction that the IRS has identified as a potentially abusive tax shelter. Thus, they disagreed with Exelon's position and asserted that the entire gain of approximately $1.2 billion was taxable in 1999. In 2013, the IRS issued a notice of deficiency to Exelon and Exelon filed a petition to initiate litigation in the United States Tax Court. In 2016, the Tax Court held that Exelon was not entitled to defer gain on the transaction. In addition to the tax and interest related to the gain deferral, the Tax Court also ruled that Exelon was liable for $90 million in penalties and interest on the penalties. Exelon has fully paid the amounts assessed resulting from the Tax Court decision.

In September 2017, Exelon appealed the Tax Court decision to the U.S. Court of Appeals for the Seventh Circuit. In October 2018, the U.S. Court of Appeals for the Seventh Circuit affirmed the Tax Court's decision. Exelon filed a petition seeking rehearing of the Seventh Circuit's decision, but the Seventh Circuit denied that petition in December 2018. Exelon has until March 5, 2019 to seek a further review by the U.S. Supreme Court.

State Income Tax Law Changes

On April 24, 2018, Maryland enacted companion bills, House Bill 1794 and Senate Bill 1090, providing for a phase in of a single sales factor apportionment formula from the current three factor formula for determining an entity's Maryland state income taxes. The single sales factor will be fully phased in by 2022.

In the second quarter of 2018, Exelon, Generation, PHI, Pepco and DPL recorded a one-time increase to deferred income taxes of approximately $16 million, $5 million, $17 million, $16 million and $1 million, respectively. At PHI, Pepco and DPL, the increase to the Maryland deferred income tax liability was offset by regulatory assets. Further, the change in tax law is not expected to have a material ongoing impact to Exelon's, Generation's, PHI's, Pepco's or DPL's future results of operations.

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

In the third quarter of 2018, Exelon reviewed and updated its marginal state income tax rates based on 2017 state apportionment rates. As a result of the rate changes, in the third quarter of 2018, Exelon, Generation, PHI and DPL recorded a one-time decrease to deferred income taxes of approximately $50 million, $53 million, $4 million and $2 million respectively. Pepco recorded a one-time increase to deferred income taxes of approximately $1 million. Exelon, PHI and DPL recorded a corresponding regulatory liability of approximately $1 million, $1 million and $2 million respectively. Pepco recorded a corresponding regulatory asset of approximately $1 million. Further, Exelon, Generation and PHI recorded a decrease to income tax expense (net of federal taxes) of approximately $50 million, $53 million and $3 million.

Allocation of Tax Benefits (All Registrants)

Generation, ComEd, PECO, BGE, PHI, Pepco, DPL and ACE are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2018, Generation, PECO, BGE, PHI and ComEd recorded an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement of $155 million, $48 million, $26 million, $2 million and $1 million respectively. Pepco, DPL, and ACE did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss.

During 2017, Generation, PECO, BGE, and PHI recorded an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement of $102 million, $16 million, $10 million and $7 million respectively. ComEd, Pepco, DPL, and ACE did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result

of a tax net operating loss.
During 2016, Generation, PECO and BGE recorded an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement of $94 million, $18 million and $8 million respectively. ComEd did not record an allocation of federal tax benefits from Exelon under the Tax Sharing Agreement as a result of a tax net operating loss. PHI, Pepco,

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

DPL and ACE did not record an allocation of federal tax benefits from Exelon as they were not a part of Exelon's 2015 consolidated tax return.

15. Asset Retirement Obligations (All Registrants)

Nuclear Decommissioning Asset Retirement Obligations

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

The following table provides a rollforward of the nuclear decommissioning ARO reflected in Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2017 to December 31, 2018:

Nuclear decommissioning ARO at January 1, 2017	$8,734
Accretion expense	458
Acquisition of FitzPatrick	444
Net increase due to changes in, and timing of, estimated future cash flows	34
Costs incurred related to decommissioning plants	(8)
Nuclear decommissioning ARO at December 31, 2017 [(a)]	9,662
Accretion expense	478
Net decrease due to changes in, and timing of, estimated future cash flows	(77)
Costs incurred related to decommissioning plants	(58)
Nuclear decommissioning ARO at December 31, 2018 [(a)] [(b)]	$10,005

____

(a) Includes $22 million and $13 million as the current portion of the ARO at December 31, 2018 and 2017, respectively, which is included in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets.

(b) Includes $772 million of ARO related to Oyster Creek which is classified as Liabilities held for sale in Exelon's and Generation's Consolidated Balance Sheets at December 31, 2018. See Note 5 — Mergers, Acquisitions and Dispositions for additional information.

The net $77 million decrease in the ARO during 2018 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include a $203 million decrease primarily due to lower estimated costs for the construction of interim spent fuel storage at TMI and a net decrease in estimated costs to decommission Calvert Cliffs, FitzPatrick, Limerick, and Salem nuclear units resulting from the completion of updated cost studies. These adjustments also include a decrease due to changes in decommissioning scenarios and their probabilities. These decreases were partially offset by a $116 million increase for the impact of the early retirement and the announced pending sale of Oyster Creek and a $122 million increase for estimated cost escalation rates, primarily for labor, energy and waste burial costs. See Note 5 — Mergers, Acquisitions and Dispositions and Note 8—Early Plant Retirements for additional information regarding Oyster Creek.

The net $34 million increase in the ARO during 2017 for changes in the amounts and timing of estimated decommissioning cash flows was driven by multiple adjustments throughout the year, some with offsetting impacts. These adjustments include a $178 million increase due to higher assumed probabilities of early retirement of Salem and a $138 million increase in TMI's ARO liability associated with the May 30, 2017 announcement to early retire the unit on September 30, 2019. The increase in TMI's ARO liability incorporates the early shutdown date, increases in the probabilities of longer term decommissioning scenarios, and an increase in the estimated costs to decommission based on an updated decommissioning cost study. See Note 8—Early Plant Retirements for

Table of Contents

additional information regarding Salem and TMI. These increases in the ARO were partially offset by a $180 million decrease for refinements in estimated fleet wide labor costs expected to be incurred for certain on-site personnel during decommissioning as well as net decreases resulting from updates to the cost studies of Clinton, Quad Cities and Dresden.

NDT Funds

NDT funds have been established for each generation station unit to satisfy Generation's nuclear decommissioning obligations. Generally, NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. On March 31, 2017, PECO filed its Nuclear Decommissioning Cost Adjustment with the PAPUC proposing an annual recovery from customers of approximately $4 million. This amount reflects a decrease from the previously approved annual collection of approximately $24 million primarily due to the removal of the collections for Limerick Units 1 and 2 as a result of the NRC approving the extension of the operating licenses for an additional 20 years. On August 8, 2017, the PAPUC approved the filing and the new rates became effective January 1, 2018.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third-party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO, and likewise Generation will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from utility customers for any of Generation's other nuclear units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to NDT funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the

Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At December 31, 2018 and 2017, Exelon and Generation had NDT funds totaling $12,695 million and $13,349 million, respectively. Included within the December 31, 2018 balance is the $890 million reclassification of Oyster Creek NDT as Assets held for sale in Exelon's and Generation's Consolidated Balance Sheets. See Note 5 — Mergers, Acquisitions and Dispositions for additional information regarding the announced pending sale of Oyster Creek. The NDT funds include $144 million and $77 million for the current portion of the NDT at December 31, 2018 and 2017, respectively, which are included in Other current assets in Exelon's and Generation's Consolidated

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Balance Sheets. See Note 11—Fair Value of Financial Assets and Liabilities for additional information related to the NDT funds.

The following table provides unrealized (losses) gains on NDT funds of Exelon and Generation for the years ended 2018, 2017 and 2016:

	2018	2017	2016
Net unrealized (losses) gains on NDT funds—Regulatory Agreement Units [a]	$ (715)	$ 455	$ 216
Net unrealized (losses) gains on NDT funds—Non-Regulatory Agreement Units [b]	(483)	521	194

(a) Net unrealized (losses) gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities in Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates in Generation's Consolidated Balance Sheets.

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

Realized earnings, including interest and dividends on the NDT funds, for the non-Regulatory Agreement Units investments are recognized when earned and are included in Other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income whereas the Regulatory Agreement Units are eliminated within Other, net.

Accounting Implications of the Regulatory Agreements with ComEd and PECO

Based on the regulatory agreements with the ICC and PAPUC that dictate Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis and the former PECO units in total, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. For the former ComEd units, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income as long as the NDT funds are expected to exceed the total estimated decommissioning obligation. For the former PECO units, decommissioning-related activities are generally offset within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income regardless of whether the NDT funds are expected to exceed or fall short of the total estimated decommissioning obligation. 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. ComEd and PECO have recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability.

Should the expected value of the NDT fund for any former ComEd unit fall below the amount of the expected 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 financial statements could be material. As of December 31, 2018, the NDT funds of each of the former ComEd units, except for Zion (see Zion Station Decommissioning below), are expected to exceed the related decommissioning obligation for each of the units. For

the purposes of making this determination, the decommissioning obligation referred to is different, as described below, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.
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 financial statements could be material.
The decommissioning-related activities related to the Non-Regulatory Agreement Units are reflected in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.
See Note 4—Regulatory Matters and Note 25—Related Party Transactions for additional information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO

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

Table of Contents

reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

Zion Station Decommissioning

In 2010, Generation completed an Asset Sale Agreement (ASA) under which ZionSolutions assumed responsibility for decommissioning Zion Station and Generation transferred to ZionSolutions substantially all the Zion Station's assets, including the related NDT funds. Pursuant to the ASA, ZionSolutions will periodically request reimbursement, subject to certain restrictions, from the Zion Station-related NDT funds for costs incurred related to its decommissioning efforts at Zion Station. As the transfer of the Zion Station assets did not qualify for asset sale accounting treatment, the related NDT funds were reclassified as pledged assets for Zion Station decommissioning, which are recorded within Other current assets within Generation's and Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction, and the transferred ARO for decommissioning was replaced with a payable for Zion Station decommissioning, which is recorded in Other current liabilities in Exelon's and Generation's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT fund assets, net of applicable taxes, are recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station.

Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of $120 million, which is included within the nuclear decommissioning ARO at December 31, 2018. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders.

The following table provides Exelon's and Generation's pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2018 and 2017:

	2018	2017
Carrying value of Zion Station pledged assets	$ 9	$ 39
Current payable to ZionSolutions [(a)]	9	37
Cumulative withdrawals by ZionSolutions to pay decommissioning costs [(b)]	965	942

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

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

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and constructed a dry cask storage facility on the land and has loaded the SNF from the SNF pools onto the dry cask storage facility at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. In accordance with the terms of the ASA, the letter of credit was reduced to $45 million in May 2018 due to the completion of key decommissioning milestones. EnergySolutions and its parent company have also provided a performance guarantee and EnergySolutions has entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

NRC Minimum Funding Requirements

NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded in Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the type of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2018 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for TMI); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2018 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning and site restoration activities, as applicable, are completed under possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the consideration of multiple end of life scenarios; (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.0% to 6.2% (as compared to a historical 5-year annual average pre-tax return of approximately 4.9%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may 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 NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial positions may be significantly adversely affected.

Generation filed its biennial decommissioning funding status report with the NRC on March 30, 2017 for all units except for Zion Station which is included in a separate report to the NRC submitted by ZionSolutions (see Zion Station Decommissioning above) and FitzPatrick which is still owned by Entergy as of the NRC reporting period. This status report demonstrated adequate decommissioning funding assurance for all units except for Peach Bottom Unit 1. As a former PECO plant, financial assurance for decommissioning Peach Bottom Unit 1 is provided by the NDT fund in addition to collections from PECO ratepayers. See NDT Funds section above for additional information.

On March 28, 2018, Generation submitted its annual decommissioning funding status report with the NRC for shutdown reactors, reactors within five years of shutdown except for Zion Station which is included in a separate report to the NRC submitted by EnergySolutions (see Zion Station Decommissioning above), and reactor involved in an acquisition. This report reflected the status of decommissioning funding assurance as of December 31, 2017 and included an update for the acquisition of FitzPatrick on March 31, 2017, the early retirement of TMI announced on May 30, 2017, an adjustment for the February 2, 2018 announced retirement date of Oyster Creek and the updated status of Peach Bottom Unit 1 based on the new collections rate described above. As of December 31, 2017, Generation provided adequate decommissioning funding assurance for all of its shutdown reactors, reactors within five years of shutdown, and reactor involved in an acquisition.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation will file its next decommissioning funding status report for all units with the NRC by March 31, 2019. This report will reflect the status of decommissioning funding assurance as of December 31, 2018. A shortfall at any unit could necessitate that Generation address the shortfall by, among other things, obtaining a parental guarantee for Generation's share of the funding assurance. However, the amount of any guarantee or other assurance will ultimately depend on the decommissioning approach, the associated level of costs, and the decommissioning trust fund investment performance going forward.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO units, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Non-Nuclear Asset Retirement Obligations (All Registrants)

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. The Utility Registrants have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected in the Registrants' Consolidated Balance Sheets from January 1, 2017 to December 31, 2018:

	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Non-nuclear AROs at January 1, 2017	$ 393	$ 199	$ 121	$ 28	$ 24	$ 14	$ 2	$ 9	$ 3
Net (decrease) increase due to changes in, and timing of, estimated future cash flows	(11)	(1)	(13)	(1)	2	2	1	1	—
Development projects	1	1	—	—	—	—	—	—	—
Accretion expense[(a)]	18	10	7	1	—	—	—	—	—
Deconsolidation of EGTP	(7)	(7)	—	—	—	—	—	—	—
Payments	(10)	(5)	(2)	(1)	(2)	—	—	—	—
Non-nuclear AROs at December 31, 2017	384	197	113	27	24	16	3	10	3
Net increase due to changes in, and timing of, estimated future cash flows[(b)]	80	35	7	—	2	36	34	1	1
Accretion expense[(a)]	16	10	4	1	1	—	—	—	—
Asset divestitures	(3)	(3)	—	—	—	—	—	—	—
Payments	(6)	(1)	(3)	—	(2)	—	—	—	—
Non-nuclear AROs at December 31, 2018	$ 471	$ 238	$ 121	$ 28	$ 25	$ 52	$ 37	$ 11	$ 4

(a) For ComEd and PECO, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

(b) In 2018, Pepco recorded an increase of $22 million in Operating and maintenance expense primarily related to asbestos identified at its Buzzard Point property as part of an annual ARO study. Buzzard Point is a waterfront property in the District of Columbia occupied by an active substation and former Pepco operated steam plant building, which Pepco retired and closed in 1981.

16. Retirement Benefits (All Registrants)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all current employees. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

employees participate in cash balance pension plans. Effective February 1, 2018, most newly-hired Generation and BSC non-represented, non-craft, employees are not eligible for pension benefits, and will instead be eligible to receive an enhanced non-discretionary employer contribution in an Exelon defined contribution savings plan. Effective January 1, 2018, most newly-hired non-represented, non-craft, employees are not eligible for OPEB benefits and employees represented by Local 614 are not eligible for retiree health care benefits.

Effective January 1, 2019, Exelon is merging the Exelon Corporation Cash Balance Pension Plan (CBPP) into the Exelon Corporation Retirement Program (ECRP). The merging of the plans is not changing the benefits offered to the plan participants and, thus, has no impact on Exelon's pension obligation. However, beginning in 2019, actuarial losses and gains related to the CBPP and ECRP will be amortized over participants’ average remaining service period of the merged ECRP rather than each individual plan.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The table below shows the pension and other postretirement benefit plans in which employees of each operating company participated at December 31, 2018:

	Operating Company(e)								
Name of Plan:	Generation	ComEd	PECO	BGE	BSC	PHI	Pepco	DPL	ACE
Qualified Pension Plans:									
Exelon Corporation Retirement Program(a)	X	X	X	X	X	X	X		
Exelon Corporation Cash Balance Pension Plan(a)	X	X	X	X	X	X	X	X	X
Exelon Corporation Pension Plan for Bargaining Unit Employees(a)	X	X			X				
Exelon New England Union Employees Pension Plan(a)	X								
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek(a)	X	X	X		X				
Pension Plan of Constellation Energy Group, Inc.(b)	X	X	X	X	X	X		X	
Pension Plan of Constellation Energy Nuclear Group, LLC(c)	X	X		X	X	X			
Nine Mile Point Pension Plan(c)	X				X				
Constellation Mystic Power, LLC Union Employees Pension Plan Including Plan A and Plan B(b)	X								
Pepco Holdings LLC Retirement Plan(d)	X	X	X	X	X	X	X	X	X
Non-Qualified Pension Plans:									
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan(a)	X	X	X		X	X			
Exelon Corporation Supplemental Management Retirement Plan(a)	X	X	X	X	X	X			
Constellation Energy Group, Inc. Senior Executive Supplemental Plan(b)	X			X	X				
Constellation Energy Group, Inc. Supplemental Pension Plan(b)	X			X	X				
Constellation Energy Group, Inc. Benefits Restoration Plan(b)	X	X		X	X	X			
Constellation Energy Nuclear Plan, LLC Executive Retirement Plan(c)	X				X				
Constellation Energy Nuclear Plan, LLC Benefits Restoration Plan(c)	X				X				
Baltimore Gas & Electric Company Executive Benefit Plan(b)	X			X	X				
Baltimore Gas & Electric Company Manager Benefit Plan(b)	X	X		X	X				
Pepco Holdings LLC 2011 Supplemental Executive Retirement Plan(d)					X	X	X	X	X
Conectiv Supplemental Executive Retirement Plan (d)	X				X	X		X	X
					X	X	X		

Pepco Holdings LLC Combined Executive Retirement Plan [d]	
Atlantic City Electric Director Retirement Plan [d]	X

394

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Operating Company[(e)]								
Name of Plan:	Generation	ComEd	PECO	BGE	BSC	PHI	Pepco	DPL	ACE
Other Postretirement Benefit Plans:									
PECO Energy Company Retiree Medical Plan[(a)]	X	X	X	X	X	X	X	X	X
Exelon Corporation Health Care Program[(a)]	X	X	X	X	X	X	X		X
Exelon Corporation Employees' Life Insurance Plan[(a)]	X	X	X	X	X				
Exelon Corporation Health Reimbursement Arrangement Plan[(a)]	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Medical Plan[(b)]	X	X	X	X	X				
Constellation Energy Group, Inc. Retiree Dental Plan[(b)]	X			X	X				
Constellation Energy Group, Inc. Employee Life Insurance Plan and Family Life Insurance Plan[(b)]	X	X	X	X	X				
Constellation Mystic Power, LLC Post-Employment Medical Account Savings Plan[(b)]	X								
Exelon New England Union Post-Employment Medical Savings Account Plan[(a)]	X								
Retiree Medical Plan of Constellation Energy Nuclear Group LLC[(c)]	X			X	X				
Retiree Dental Plan of Constellation Energy Nuclear Group LLC[(c)]	X			X	X				
Nine Mile Point Nuclear Station, LLC Medical Care and Prescription Drug Plan for Retired Employees[(c)]	X				X				
Pepco Holdings LLC Welfare Plan for Retirees[(d)]	X	X	X	X	X	X	X	X	X

(a) These plans are collectively referred to as the legacy Exelon plans.
(b) These plans are collectively referred to as the legacy Constellation Energy Group (CEG) Plans.
(c) These plans are collectively referred to as the legacy CENG plans.
(d) These plans are collectively referred to as the legacy PHI plans.
(e) Employees generally remain in their legacy benefit plans when transferring between operating companies.

Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Exelon has elected that the trusts underlying these plans be treated as qualified trusts under the IRC. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and OPEB plans as an asset or liability on its balance sheet, with offsetting entries to AOCI and regulatory assets (liabilities), in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31.

During the first quarter of 2018, Exelon received an updated valuation of its pension and OPEB to reflect actual census data as of January 1, 2018. This valuation resulted in an increase to the pension and OPEB obligations of $23 million and $14 million, respectively. Additionally, accumulated other comprehensive loss decreased by $18 million (after-tax) and regulatory assets and liabilities increased by $61 million and $1 million, respectively.

395

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

In connection with the acquisition of FitzPatrick in 2017, Exelon recorded pension and OPEB obligations for FitzPatrick employees of $16 million and $17 million, respectively. See Note 5 — Mergers, Acquisitions and Dispositions for additional information of the acquisition of FitzPatrick.

The following tables provide a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
Exelon	2018	2017	2018	2017
Change in benefit obligation:				
Net benefit obligation at beginning of year	$22,337	$21,060	$ 4,856	$ 4,457
Service cost	405	387	112	106
Interest cost	802	842	175	182
Plan participants' contributions	—	—	45	53
Actuarial (gain) loss[(a)]	(1,561)	1,182	(540)	350
Plan amendments	(4)	9	—	—
Acquisitions[(b)]	—	16	—	17
Settlements	(48)	(34)	(4)	—
Gross benefits paid	(1,239)	(1,125)	(275)	(309)
Net benefit obligation at end of year	$20,692	$22,337	$ 4,369	$ 4,856

	Pension Benefits		Other Postretirement Benefits	
Exelon	2018	2017	2018	2017
Change in plan assets:				
Fair value of net plan assets at beginning of year	$18,573	$16,791	$ 2,732	$ 2,578
Actual return on plan assets	(945)	2,600	(136)	346
Employer contributions	337	341	46	64
Plan participants' contributions	—	—	45	53
Gross benefits paid	(1,239)	(1,125)	(275)	(309)
Settlements	(48)	(34)	(4)	—
Fair value of net plan assets at end of year	$16,678	$18,573	$ 2,408	$ 2,732

(a) The pension actuarial gain in 2018 primarily reflects an increase in the discount rate. The OPEB actuarial gain in 2018 primarily reflects an increase in the discount rate and favorable health care claims experience. The pension and OPEB actuarial losses in 2017 primarily reflect a decrease in the discount rate.
(b) Exelon recorded pension and OPEB obligations associated with its acquisition of Fitzpatrick on March 31, 2017.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
Exelon	2018	2017	2018	2017
Other current liabilities	$26	$28	$ 33	$ 31
Pension obligations	3,988	3,736	—	—
Non-pension postretirement benefit obligations	—	—	1,928	2,093
Unfunded status (net benefit obligation less plan assets)	$4,014	$3,764	$ 1,961	$ 2,124

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

PBO in excess of plan assets	Exelon	
	2018	2017
Projected benefit obligation	$20,692	$22,337
Fair value of net plan assets	16,678	18,573

ABO in excess of plan assets	Exelon	
	2018	2017
Projected benefit obligation	$20,692	$22,337
Accumulated benefit obligation	19,656	21,153
Fair value of net plan assets	16,678	18,573

On a PBO basis, the Exelon plans were funded at 81% and 83% at December 31, 2018 and 2017, respectively. On an ABO basis, the Exelon plans were funded at 85% and 88% at December 31, 2018 and 2017, respectively. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The majority of the 2018 pension benefit cost for the Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.62%. The majority of the 2018 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.60% for funded plans and a discount rate of 3.61%.

A portion of the net periodic benefit cost for all plans is capitalized within the Consolidated Balance Sheets. The following tables present the components of Exelon’s net periodic benefit costs, prior to capitalization, for the years ended December 31, 2018, 2017 and 2016 and PHI's net periodic benefit costs, prior to capitalization, for the predecessor period of January 1, 2016 to March 23, 2016.

	Pension Benefits			Other Postretirement Benefits		
Exelon	2018	2017(a)	2016(b)	2018	2017(a)	2016(b)
Components of net periodic benefit cost:						
Service cost	$405	$387	$354	$112	$106	$107
Interest cost	802	842	830	175	182	185
Expected return on assets	(1,252)	(1,196)	(1,141)	(173)	(162)	(162)
Amortization of:						
Prior service cost (credit)	2	1	14	(186)	(188)	(185)
Actuarial loss	629	607	554	66	61	63
Settlement and other charges(c)	3	3	2	1	—	—
Net periodic benefit cost	$589	$644	$613	$(5)	$(1)	$8

(a) FitzPatrick net benefit costs are included for the period after acquisition.
(b) PHI net periodic benefit costs for the period prior to the merger are not included in the table above.
(c) 2016 amount includes an additional termination benefit for PHI.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

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

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon’s Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets (liabilities) for the years ended December 31, 2018, 2017 and 2016 for all plans combined and the components of PHI's predecessor AOCI and regulatory assets (liabilities) for the period January 1, 2016 to March 23, 2016.

	Pension Benefits			Other Postretirement Benefits		
Exelon	2018	2017	2016[(a)]	2018	2017	2016[(a)]
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):						
Current year actuarial (gain) loss	$635	$(222)	$644	$(232)	$166	$(101)
Amortization of actuarial loss	(629)	(607)	(554)	(66)	(61)	(63)
Current year prior service cost (credit)	(4)	9	(60)	—	—	—
Amortization of prior service (cost) credit	(2)	(1)	(14)	186	188	185
Settlements	(3)	(3)	—	—	—	—
Acquisitions	—	—	994	—	—	94
Total recognized in AOCI and regulatory assets (liabilities)	$(3)	$(824)	$1,010	$(112)	$293	$115
Total recognized in AOCI	$3	$(401)	$51	$(55)	$168	$20
Total recognized in regulatory assets (liabilities)	$(6)	$(423)	$959	$(57)	$125	$95

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI	Predecessor Pension Benefits January 1, 2016 to March 23, 2016	Predecessor Other Postretirement Benefits January 1, 2016 to March 23, 2016
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets (liabilities):		
Current year actuarial loss (gain)	$ —	$ —
Amortization of actuarial loss	(14)	(2)
Amortization of prior service (cost) credit	—	3
Total recognized in AOCI and regulatory assets (liabilities)	$ (14)	$ 1
Total recognized in AOCI	$ (1)	$ —
Total recognized in regulatory assets (liabilities)	$ (13)	$ 1

____
(a) 2016 amounts include PHI for the period of March 24, 2016 through December 31, 2016.

The following table provides the components of gross accumulated other comprehensive loss and regulatory assets (liabilities) that have not been recognized as components of periodic benefit cost at December 31, 2018 and 2017, respectively, for all plans combined:

	Exelon Pension Benefits		Exelon Other Postretirement Benefits	
	2018	2017	2018	2017
Prior service (credit) cost	$(29)	$(24)	$ (337)	$ (522)
Actuarial loss	7,558	7,556	531	829
Total	$7,529	$7,532	$ 194	$ 307
Total included in AOCI	$3,899	$3,896	$ 70	$ 125
Total included in regulatory assets (liabilities)	$3,630	$3,636	$ 124	$ 182

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 12.0 years, 11.8 years and 11.9 years for the years ended December 31, 2018, 2017 and 2016, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants’ average remaining service period to benefit eligibility age and amortizes 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 8.8 years, 8.8 years and 9.0 years for the years ended

December 31, 2018, 2017 and 2016, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.5 years, 9.6 years and 9.7 years for the years ended December 31, 2018, 2017 and 2016, respectively.

Assumptions

399

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and inputs and accounting policy elections. The measurement of benefit obligations and costs is impacted by several assumptions and inputs, including the discount rate applied to benefit obligations, the long-term EROA, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors. When developing the required assumptions, Exelon considers historical information as well as future expectations.

Expected Rate of Return. In selecting the EROA, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

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's mortality assumption is supported by an actuarial experience study of Exelon's plan participants and utilizes the IRS's RP–2000 base table projected to 2012 with improvement scale AA and projected thereafter with generational improvement scale BB two-dimensional adjusted to a 0.75% long-term rate reached in 2027. There were no changes to the mortality assumption in 2016, 2017 or 2018.

The following assumptions were used to determine the benefit obligations for the plans at December 31, 2018, 2017 and 2016. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
Exelon	2018	2017	2016[f]	2018	2017	2016[f]
Discount rate	4.31% [a]	3.62 % [b]	4.04 % [c]	4.30% [a]	3.61 % [b]	4.04 % [c]
Investment Crediting Rate	4.46%	4.00 %	4.46 %	N/A	N/A	N/A
Rate of compensation increase	[d]	[d]	[e]	[d]	[d]	[e]
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.00% with ultimate trend	5.00% with ultimate trend of 5.00% in	5.00% decreasing to ultimate

	of 5.00% in 2017	2017	trend of 5.00% in 2017

(a) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2018. Certain benefit plans used individual rates ranging from 4.13% - 4.36% and 4.27% - 4.38% for pension and other postretirement plans, respectively.

(b) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2017. Certain benefit plans used individual rates ranging from 3.49% - 3.65% and 3.57% - 3.68% for pension and other postretirement plans, respectively.

(c) The discount rates above represent the blended rates used to determine the majority of Exelon's pension and other postretirement benefits obligations as of December 31, 2016. Certain benefit plans used individual rates ranging from 3.66% - 4.11% and 4.00% - 4.17% for pension and other postretirement plans, respectively.

(d) 3.25% through 2019 and 3.75% thereafter.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(e) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.
(f) Obligation was not remeasured for the PHI predecessor for the period from January 1, 2016, to March 23, 2016.

The following assumptions were used to determine the net periodic benefit costs for the plans for the years ended December 31, 2018, 2017 and 2016, as well as for the PHI predecessor period January 1, 2016 to March 23, 2016:

	Pension Benefits			Other Postretirement Benefits		
Exelon	2018	2017	2016	2018	2017	2016
Discount rate	3.62% [a]	4.04% [b]	4.29% [c]	3.61% [a]	4.04% [b]	4.29% [c]
Investment Crediting Rate	4.00%	4.46%	5.31%	N/A	N/A	N/A
Expected return on plan assets	7.00% [d]	7.00% [d]	7.00% [d]	6.60% [d]	6.58% [d]	6.71% [d]
Rate of compensation increase	[e]	[f]	[f]	[e]	[f]	[f]
Mortality table	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)	RP-2000 table projected to 2012 with improvement scale AA, with Scale BB-2D improvements (adjusted)
Health care cost trend on covered charges	N/A	N/A	N/A	5.00% with ultimate trend of 5.00% in 2017	5.00% with ultimate trend of 5.00% in 2017	5.50% decreasing to ultimate trend of 5.00% in 2017

	Predecessor	
	Pension Benefits	Other Postretirement Benefits
PHI	January 1, 2016 to March 23, 2016	January 1, 2016 to March 23, 2016
Discount rate	4.65%/4.55% [g]	4.55%
Investment crediting rate	2.89%	N/A
Expected return on plan assets[h]	6.50%	6.75%

Rate of compensation increase	5.00 %	5.00 %
Mortality table	RP-2014 table with improvement scale MP-2015	RP-2014 table with improvement scale MP-2015
Health care cost trend on covered charges	N/A	6.33% pre-65 and 5.40% post-65 decreasing to ultimate trend of 5.00% in 2020

(a) The discount rates above represent the blended rates used to establish the majority of Exelon’s pension and other postretirement benefits costs for the year ended December 31, 2018. Certain benefit plans used individual rates ranging from 3.49%-3.65% and 3.57%-3.68% for pension and other postretirement plans, respectively.

(b) The discount rates above represent the blended rates used to establish the majority of Exelon's pension and other postretirement benefits costs for the year ended December 31, 2017. Certain benefit plans used individual rates ranging from 3.66%-4.11% and 4.00%-4.17% for pension and other postretirement plans, respectively.

(c) The discount rates above represent the blended rates used to establish the majority of Exelon’s pension and other postretirement benefits costs for the year ended December 31, 2016. Certain benefit plans used the individual rates ranging from 3.68%-4.14% and 4.32%-4.43% for pension and other postretirement plans, respectively.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

(d) Not applicable to pension and other postretirement benefit plans that do not have plan assets.
(e) 3.25% through 2019 and 3.75% thereafter.
(f) The legacy Exelon, CEG and CENG pension and other postretirement plans used a rate of compensation increase of 3.25% through 2019 and 3.75% thereafter, while the legacy PHI pension and other postretirement plans used a weighted-average rate of compensation increase of 5% for all periods.
(g) The discount rate for the qualified and non-qualified pension plans was 4.65% and 4.55%, respectively.
(h) Expected return on other postretirement benefit plan assets is pre-tax.

Contributions

The following tables provide contributions to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2018[a]	2017[a]	2016[a]	2018	2017	2016
Exelon	$337	$ 341	$ 347	$ 46	$ 64	$ 50
Generation	128	137	140	11	11	12
ComEd	38	36	33	4	5	5
PECO	28	24	30	—	—	—
BGE	40	39	31	14	14	18
BSC[b]	41	38	39	5	2	3
Pepco	6	62	24	11	10	8
DPL	—	—	22	—	2	—
ACE	6	—	15	—	20	2
PHISCO [c]	50	5	17	1	—	2

	Pension Benefits				Other Postretirement Benefits			
	Successor			Predecessor	Successor			Predecessor
	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016	2018	2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
PHI	$62	$ 67	$ 74	$ 4	$ 12	$ 32	$ 12	$ —

(a) Exelon's and Generation's pension contributions include $21 million and $25 million related to the legacy CENG plans that was funded by CENG as provided in an Employee Matters Agreement (EMA) between Exelon and CENG for the years ended December 31, 2017 and 2016, respectively. There were no pension contributions for the year ended December 31, 2018.
(b) Includes $2 million, $4 million, and $6 million of pension contributions funded by Exelon Corporate, for the years ended December 31, 2018, 2017, and 2016, respectively.
(c) PHISCO's pension contributions for the year ended December 31, 2016 include $4 million of contributions made prior to the closing of Exelon's merger with PHI on March 23, 2016.

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 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). The projected contributions below reflect a funding strategy of contributing the greater of (1) $300 million until all the qualified plans are fully funded on an ABO basis, and (2) the minimum amounts under ERISA to meet minimum contribution requirement and/or avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. Unlike the qualified pension plans, Exelon’s non-qualified pension plans are not funded, given that they are not subject to statutory minimum contribution requirements.

While other postretirement plans are also not subject to statutory minimum contribution requirements, Exelon does fund certain of its plans. For Exelon's funded OPEB plans, contributions generally equal accounting costs, however,

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon’s management has historically considered several factors in determining the level of contributions to its other postretirement benefit plans, including liabilities management, levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). The amounts below include benefit payments related to unfunded plans.
The following table provides all registrants' planned contributions to the qualified pension plans, planned benefit payments to non-qualified pension plans, and planned contributions to other postretirement plans in 2019:

	Qualified Pension Plans	Non-Qualified Pension Plans	Other Postretirement Benefits
Exelon	$ 301	$ 25	$ 44
Generation	135	7	13
ComEd	65	1	2
PECO	25	1	—
BGE	34	1	15
BSC	41	7	2
PHI	1	8	12
Pepco	—	2	10
DPL	—	1	—
ACE	—	—	1
PHISCO	1	5	1

Estimated Future Benefit Payments
Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2018 were:

	Pension Benefits	Other Postretirement Benefits
2019	$1,196	$ 255
2020	1,221	263
2021	1,258	269
2022	1,284	274
2023	1,302	282
2024 through 2028	6,770	1,483
Total estimated future benefit payments through 2028	$13,031	$ 2,826

Allocation to Exelon Subsidiaries
All registrants account for their participation in Exelon’s pension and other postretirement benefit plans by applying multi-employer accounting. Employee-related assets and liabilities, including both pension and postretirement liabilities, for the legacy Exelon plans were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon’s corporate restructuring. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001. Historically, Exelon has allocated the components of pension and other postretirement costs to the subsidiaries in the legacy Exelon plans based upon several factors, including the measures of active employee participation in each plan. Pension and other postretirement benefit contributions were allocated to legacy Exelon subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. Beginning in 2015, Exelon began allocating costs related to its legacy Exelon pension and other postretirement benefit plans to its subsidiaries based on both active and retired employee participation and contributions are allocated based on accounting cost. The impact of this

allocation methodology change was not material to any Registrant. For legacy CEG, legacy

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

CENG, FitzPatrick, and legacy PHI plans, components of pension and other postretirement benefit costs and contributions have been, and will continue to be, allocated to the subsidiaries based on employee participation (both active and retired).

The amounts below represent the Registrants' as well as BSC's and PHISCO's pension and OPEB costs. As a result of new pension guidance effective on January 1, 2018, certain balances have been reclassified on Exelon's Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2017 and 2016. For Exelon, the service cost component is included in Operating and maintenance expense and Property, plant and equipment, net, for the years ended December 31, 2018, 2017 and 2016, while the non–service cost components are included in Other, net and Regulatory assets for year ended December 31, 2018 and in Other, net and Property, plant and equipment, net, for the years ended December 31, 2017 and 2016. For Generation and the Utility Registrants, the service cost and non–service cost components are included in Operating and maintenance expense and Property, plant and equipment, net on their consolidated financial statements for the years ended December 31, 2018, 2017 and 2016.

For the Years Ended December 31,	Exelon	Generation[a]	ComEd	PECO	BGE	BSC[b]	Pepco[c]	DPL[c]	ACE[c]	PHISCO[c][d]
2018	$ 583	$ 204	$ 177	$ 18	$ 60	$ 57	$ 15	$ 6	$ 12	$ 34
2017	643	227	176	29	64	53	25	13	13	43
2016	621	218	166	33	68	48	31	18	15	47

PHI	Successor			Predecessor
	For the Year Ended December 31, 2018	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	January 1, 2016 to March 23, 2016
Pension and Other Postretirement Benefit Costs	$67	$ 94	$ 88	$ 23

____

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

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

(c) Pepco's, DPL's, ACE's and PHISCO's pension and postretirement benefit costs for the year ended December 31, 2016 include $7 million, $4 million, $3 million and $9 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016.

(d) These amounts represent amounts billed to Pepco, DPL and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented a liability hedging investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

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 Exelon’s pension and other postretirement benefit plans for the year ended December 31, 2018 were (4.86)% and (4.66)%, respectively, compared to an expected long-term return assumption of 7.00% and 6.60%, respectively.

Exelon used an EROA of 7.00% and 6.67% to estimate its 2019 pension and other postretirement benefit costs, respectively.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon's pension and other postretirement benefit plan target asset allocations at December 31, 2018 and 2017 asset allocations were as follows:

Pension Plans

			Exelon Percentage of Plan Assets at December 31,			
Asset Category	Target Allocation		2018		2017	
Equity securities	35	%	32	%	35	%
Fixed income securities	37	%	38		39	
Alternative investments[(a)]	28	%	30		26	
Total			100	%	100	%

Other Postretirement Benefit Plans

			Exelon Percentage of Plan Assets at December 31,			
Asset Category	Target Allocation		2018		2017	
Equity securities	47	%	44	%	47	%
Fixed income securities	28	%	28		28	
Alternative investments[(a)]	25	%	28		25	
Total			100	%	100	%

(a) Alternative investments include private equity, hedge funds, real estate, and private credit.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2018. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2018, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Fair Value Measurements
The following tables present pension and other postretirement benefit plan assets measured and recorded at fair value in the Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2018 and 2017:
Exelon

December 31, 2018[a]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$350	$—	$—	$ —	$350
Equities[c]	3,364	—	2	1,980	5,346
Fixed income:					
U.S. Treasury and agencies	996	173	—	—	1,169
State and municipal debt	—	59	—	—	59
Corporate debt	—	3,716	216	—	3,932
Other[c]	—	329	—	613	942
Fixed income subtotal	996	4,277	216	613	6,102
Private equity	—	—	—	1,219	1,219
Hedge funds	—	—	—	1,608	1,608
Real estate	—	—	—	1,029	1,029
Private credit	—	—	268	798	1,066
Pension plan assets subtotal	$4,710	$4,277	$486	$ 7,247	$16,720

December 31, 2018[a]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$22	$—	$—	$ —	$22
Equities	537	2	—	508	1,047
Fixed income:					
U.S. Treasury and agencies	11	56	—	—	67
State and municipal debt	—	126	—	—	126
Corporate debt	—	48	—	—	48
Other	183	72	—	170	425
Fixed income subtotal	194	302	—	170	666
Hedge funds	—	—	—	411	411
Real estate	—	—	—	132	132
Private credit	—	—	—	132	132
Other postretirement benefit plan assets subtotal	$753	$304	$—	$ 1,353	$2,410
Total pension and other postretirement benefit plan assets[e]	$5,463	$4,581	$486	$ 8,600	$19,130

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

December 31, 2017[a][b]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Pension plan assets					
Cash equivalents	$585	$—	$ —	$ —	$585
Equities[c]	3,565	—	2	3,077	6,644
Fixed income:					
U.S. Treasury and agencies	1,150	159	—	—	1,309
State and municipal debt	—	64	—	—	64
Corporate debt	—	3,931	232	—	4,163
Other[c]	—	447	—	756	1,203
Fixed income subtotal	1,150	4,601	232	756	6,739
Private equity	—	—	—	1,034	1,034
Hedge funds	—	—	—	1,770	1,770
Real estate	—	—	—	884	884
Private credit[d]	—	—	224	695	919
Pension plan assets subtotal	$5,300	$4,601	$ 458	$ 8,216	$18,575

December 31, 2017[a][b]	Level 1	Level 2	Level 3	Not subject to leveling	Total
Other postretirement benefit plan assets					
Cash equivalents	$29	$—	$ —	$ —	$29
Equities	523	2	—	764	1,289
Fixed income:					
U.S. Treasury and agencies	13	56	—	—	69
State and municipal debt	—	136	—	—	136
Corporate debt	—	47	—	—	47
Other	225	71	—	185	481
Fixed income subtotal	238	310	—	185	733
Hedge funds	—	—	—	430	430
Real estate	—	—	—	124	124
Private credit	—	—	—	123	123
Other postretirement benefit plan assets subtotal	$790	$312	$ —	$ 1,626	$2,728
Total pension and other postretirement benefit plan assets[e]	$6,090	$4,913	$ 458	$ 9,842	$21,303

(a) See Note 11—Fair Value of Financial Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Effective March 31, 2017, Exelon became sponsor of FitzPatrick's defined benefit pension and other postretirement benefit plans, and assumed FitzPatrick's benefit plan obligations.
(c) Includes derivative instruments of less than $1 million and $6 million, which have a total notional amount of $5,991 million and $3,606 million at December 31, 2018 and 2017, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company’s exposure to credit or market loss.
(d) Prior year amounts reflect a reclassification from Not subject to leveling into Level 3.

(e) Excludes net liabilities of $44 million and net assets of $2 million at December 31, 2018 and 2017, respectively, which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables or payables related to pending securities sales and purchases, interest and dividends receivable.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2018 and 2017:
Exelon

	Fixed Income	Equities	Private Credit	Total
Pension Assets				
Balance as of January 1, 2018	$ 232	$ 2	$ 224	$458
Actual return on plan assets:				
Relating to assets still held at the reporting date	(14)	—	9	(5)
Relating to assets sold during the period	(1)	—	—	(1)
Purchases, sales and settlements:				
Purchases	19	—	35	54
Sales	(8)	—	—	(8)
Settlements(b)	(12)	—	—	(12)
Balance as of December 31, 2018	$ 216	$ 2	$ 268	$486

	Fixed income	Equities	Private Credit (a)	Total
Pension Assets				
Balance as of January 1, 2017	$ 206	$ 2	$ 229	$437
Actual return on plan assets:				
Relating to assets still held at the reporting date	11	—	29	40
Purchases, sales and settlements:				
Purchases	31	—	5	36
Sales	(16)	—	—	(16)
Settlements(b)	—	—	(39)	(39)
Balance as of December 31, 2017	$ 232	$ 2	$ 224	$458

(a) Prior year amounts reflect a reclassification from Not subject to leveling into Level 3.
(b) Represents cash settlements only.

There were no significant transfers between Level 1 and Level 2 during the year ended December 31, 2018 for the pension and other postretirement benefit plan assets.

Valuation Techniques Used to Determine Fair Value

Cash equivalents. Investments with original maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equities. Equities consist of individually held equity securities, equity mutual funds and equity commingled funds in domestic and foreign markets. With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are generally obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually, including real estate investment trusts, rights and warrants, are primarily traded on exchanges that contain only actively traded securities due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

markets and are categorized as Level 1. Certain private placement equity securities are categorized as Level 3 because they are not publicly traded and are priced using significant unobservable inputs.

Equity commingled funds and mutual funds are maintained by investment companies, and certain investments are held in accordance with a stated set of fund objectives, which are consistent with the plans' overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, U.S government securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, commingled funds, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. With respect to individually held fixed income securities, the trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. Certain private placement fixed income securities have been categorized as Level 3 because they are priced using certain significant unobservable inputs and are typically illiquid. The remaining fixed income securities, including certain other fixed income investments, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Other fixed income investments primarily consist of fixed income commingled funds and mutual funds, which are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities and are not classified within the fair value hierarchy. These investments typically can be redeemed monthly with 30 or less days of notice and without further restrictions.

Derivative instruments consisting primarily of futures and swaps to manage risk are recorded at fair value. Over-the-counter derivatives are valued daily based on quoted prices in active markets and trade in open markets, and have been categorized as Level 1. Derivative instruments other than over-the-counter derivatives are valued based on external price data of comparable securities and have been categorized as Level 2.

Private equity. Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include unobservable inputs such as cost, operating results, discounted future cash flows and market based comparable data. The fair value of private equity investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Hedge funds. Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or its equivalent as a practical expedient, and therefore, hedge funds are not classified within the fair value hierarchy. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate.
Real estate. Real estate funds are funds with a direct investment in pools of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

sources with professional qualifications. These valuation inputs are not highly observable. The fair value of real estate investments is determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Private credit. Private credit investments primarily consist of limited partnerships that invest in private debt strategies. These investments are generally less liquid assets with an underlying term of 3 to 5 years and are intended to be held to maturity. The fair value of these investments is determined by the fund manager or administrator and include unobservable inputs such as cost, operating results, and discounted cash flows. Private credit investments are categorized as Level 3 because they are based largely on inputs that are unobservable and utilize complex valuation models. The fair value of private credit funds are determined using NAV or its equivalent as a practical expedient, and therefore, these investments are not classified within the fair value hierarchy.

Defined Contribution Savings Plan (All Registrants)

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2018, 2017 and 2016:

For the Year Ended December 31,	Exelon[(a)]	Generation[(a)]	ComEd	PECO	BGE	BSC[(b)]	Pepco[(c)]	DPL[(c)]	ACE	PHISCO[(c)(d)]
2018	$ 179	$ 86	$ 37	$ 9	$ 12	$ 22	$ 3	$ 2	$ 2	$ 6
2017	128	55	31	10	10	9	3	2	2	6
2016	164	79	34	10	12	19	3	2	2	6

PHI	Successor For the Year Ended December 31, 2018	For the Year Ended December 31, 2017	March 24, 2016 to December 31, 2016	Predecessor January 1, 2016 to March 23, 2016
Saving Plan Matching Contributions	$13	$ 13	$ 10	$ 3

(a) Includes $13 million related to CENG for the year ended December 31, 2016.

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

(c) Pepco's, DPL's and PHISCO's matching contributions include $1 million, $1 million and $1 million, respectively, of costs incurred prior to the closing of Exelon's merger with PHI on March 23, 2016, which is not included in Exelon's matching contributions for the year ended December 31, 2016.

(d) These amounts primarily represent amounts billed to Pepco, DPL, and ACE through intercompany allocations. These amounts are not included in Pepco, DPL or ACE amounts above.

17. Severance (All Registrants)

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

410

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Severance Liability

Amounts included in the table below represent the severance liability recorded for employees of each Registrant. Exelon's severance liability includes amounts related to BSC that are billed through intercompany allocations.

Severance Liability	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Balance at December 31, 2016	$ 88	$ 36	$ 3	$ —	$ —	$29	$ —	$ —	$ —
Severance costs[a]	35	31	2	—	—	3	—	—	—
Payments	(29)	(9)	(2)	—	—	(12)	—	—	—
Balance at December 31, 2017	$ 94	$ 58	$ 3	$ —	$ —	$20	$ —	$ —	$ —
Severance costs[a]	35	9	1	—	1	5	1	—	—
Payments	(52)	(20)	(2)	—	—	(18)	(1)	—	—
Balance at December 31, 2018	$ 77	$ 47	$ 2	$ —	$ 1	$7	$ —	$ —	$ —

(a) Includes salary continuance and health and welfare severance benefits.

Severance Costs Related to the PHI Merger

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

For the years ended December 31, 2018 and December 31, 2017, the PHI Merger severance costs were immaterial. For the year ended December 31, 2016, the Registrants recorded the following severance costs associated with the identified job reductions within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Severance Benefits	Exelon	Generation	ComEd	PECO	BGE	PHI	Pepco	DPL	ACE
Severance costs[a]	$ 57	$ 9	$ 2	$ 1	$ 1	$44	$ 21	$ 13	$ 10

(a) The amounts above for Generation, ComEd, PECO, BGE, Pepco, DPL, and ACE include $8 million, $2 million, $1 million, $1 million, $20 million, $12 million and $10 million, respectively, for amounts billed by BSC and/or PHISCO through intercompany allocations.

PHI, Pepco, DPL and ACE recorded regulatory assets for merger related integration costs which include a portion of these severance costs. These regulatory assets are either currently being recovered in rates or are deemed probable of recovery in future rates. See Note 4 — Regulatory Matters for additional information.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

18. Shareholders' Equity (Exelon, ComEd, PECO, BGE, Pepco, DPL and ACE)
The following table presents common stock authorized and outstanding as of December 31, 2018 and 2017:

			December 31,	
			2018	2017
	Par Value	Shares Authorized	Shares Outstanding	
Common Stock				
Exelon	no par value	2,000,000,000	968,187,955	963,335,888
ComEd	$ 12.50	250,000,000	127,021,331	127,021,246
PECO	no par value	500,000,000	170,478,507	170,478,507
BGE	no par value	1,500	1,000	1,000
Pepco	$ 0.01	200,000,000	100	100
DPL	$ 2.25	1,000	1,000	1,000
ACE	$ 3.00	25,000,000	8,546,017	8,546,017

ComEd had 60,285 and 60,584 warrants outstanding to purchase ComEd common stock at December 31, 2018 and 2017, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2018 and 2017, 20,095 and 20,195 shares of common stock, respectively, were reserved for the conversion of warrants.

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share. In connection with such offering, Exelon entered into forward sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreement by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion, which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. The net proceeds were used to fund the merger with PHI and related costs and expenses, and for general corporate purposes. The forward sale agreements are classified as equity transactions. As a result, no amounts were recorded in the consolidated financial statements until the July 2015 settlement of the forward sale agreements. However, prior to the July 2015 settlement, incremental shares, if any, were included within the calculation of diluted EPS using the treasury stock method.

Concurrent with the forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. On June 1, 2017, Exelon settled the forward purchase contract, which was a component of the June 2014 equity units, through the issuance of Exelon common stock from treasury stock. See Note 13 — Debt and Credit Agreements for additional information on the equity units.

Share Repurchases

Share Repurchase Programs

There currently is no Exelon Board of Director authority to repurchase shares. Any previous shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon’s management. Under the previous share repurchase programs, 2 million shares of common stock were held as treasury stock with a historical cost of $123 million at December 31, 2018 and 2017. During 2017, Exelon issued approximately 33 million shares of Exelon common stock from treasury stock in order to settle the forward purchase contract, which was a component of the June 2014 equity units discussed above. During 2018, 2017, and 2016 Exelon had no common stock repurchases.

Preferred and Preference Securities of Subsidiaries

At December 31, 2018 and 2017, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2018 and 2017, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.
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.

19. Stock-Based Compensation Plans (All Registrants)

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes stock options, restricted stock units and performance share awards. At December 31, 2018, there were approximately 11 million shares authorized for issuance under the LTIP. For the years ended December 31, 2018, 2017 and 2016, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.
ComEd, PECO, BGE and PHI grant cash awards. The following tables do not include expense related to these plans as they are not considered stock-based compensation plans under the applicable authoritative guidance.
In connection with the acquisition of PHI in March 2016, 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.
For the years ended December 31, 2018, 2017 and 2016, there were no significant modifications to the granted stock based awards.
The following tables present the stock-based compensation expense included in Exelon's and PHI’s Consolidated Statements of Operations and Comprehensive Income for the years ended December 31, 2018, 2017 and 2016 and PHI's predecessor period January 1, 2016 to March 23, 2016:

Exelon	Year Ended December 31,		
Components of Stock-Based Compensation Expense	2018	2017	2016[(a)]
Performance share awards	$143	$107	$93
Restricted stock units	57	77	75
Stock options	—	—	—
Other stock-based awards	8	7	7
Total stock-based compensation expense included in operating and maintenance expense	208	191	175
Income tax benefit	(54)	(74)	(68)
Total after-tax stock-based compensation expense	$154	$117	$107

(a) 2016 amounts include expense related to stock-based compensation granted to eligible PHI employees since the merger date of March 23, 2016.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PHI

Components of Stock-Based Compensation Expense	Predecessor January 1 to March 23, 2016
Time-based restricted stock units	$ 2
Performance-based restricted stock units	1
Time-based restricted stock awards	—
Total stock-based compensation expense included in operating and maintenance expense	3
Income tax benefit	(1)
Total after-tax stock-based compensation expense	$ 2

The following tables present the Registrants' stock-based compensation expense (pre-tax) for the years ended December 31, 2018, 2017 and 2016, as well as for the PHI predecessor period January 1, 2016 to March 23, 2016:

	Year Ended December 31,		
Subsidiaries	2018	2017	2016
Exelon	$208	$191	$175
Generation	77	88	78
ComEd	8	7	8
PECO	5	3	3
BGE	3	1	1
BSC[(a)]	111	88	81
PHI Successor[(b)(c)]	4	4	4

	Predecessor January 1 to March 23, 2016
PHI	$ 3

____
(a) These amounts primarily represent amounts billed to Exelon’s subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO, BGE or PHI amounts above.
(b) Pepco's, DPL's and ACE's stock-based compensation expense for the years ended December 31, 2018 and 2017 was not material.
(c) These amounts primarily represent amounts billed to PHI’s subsidiaries through PHISCO intercompany allocations.

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2018, 2017 and 2016 for Exelon or PHI, or for PHI during the predecessor period January 1, 2016 to March 23, 2016.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and the distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The following tables present information regarding Exelon's tax benefits for the years ended December 31, 2018, 2017 and 2016.

Exelon	Year Ended December 31,		
	2018	2017	2016
Realized tax benefit when exercised/distributed:			
Restricted stock units	28	35	27
Performance share awards	16	29	18

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock were granted under the LTIP through 2012. Due to changes in the LTIP, there were no stock options granted in 2018, 2017 and 2016. For all stock options granted through 2012, the exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. The vesting period of stock options is generally four years and all stock options will expire no later than ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

The following table presents information with respect to stock option activity for the year ended December 31, 2018:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2017	6,723,611	$ 47.69	2.65	$ 7
Options exercised	(1,522,952)	36.54		
Options forfeited	—	—		
Options expired	(1,173,007)	74.99		
Balance of shares outstanding at December 31, 2018	4,027,652	$ 43.95	2.90	$ 14
Exercisable at December 31, 2018 [(a)]	4,027,652	$ 43.95	2.90	$ 14

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
Intrinsic value[(a)]	$12	$ 15	$ 11
Cash received for exercise price	56	107	19

(a) The difference between the market value on the date of exercise and the option exercise price.

415

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2016, all stock options were vested and at December 31, 2018 there were no unrecognized compensation costs related to nonvested stock options.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon’s nonvested restricted stock unit activity for the year ended December 31, 2018:

Exelon

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2017[a]	3,389,503	$ 32.24
Granted	1,321,988	38.60
Vested	(1,845,300)	32.03
Forfeited	(65,046)	32.96
Undistributed vested awards [b]	(507,804)	36.76
Nonvested at December 31, 2018[a]	2,293,341	$ 35.06

(a) Excludes 1,131,487 and 1,488,383 of restricted stock units issued to retirement-eligible employees as of December 31, 2018 and 2017, respectively, as they are fully vested.

(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2018.

For Exelon, the weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2018, 2017 and 2016 was $38.60, $34.98 and $28.14, respectively. At December 31, 2018 and 2017, Exelon had obligations related to outstanding restricted stock units not yet settled of $83 million and $108 million, respectively, which are included in common stock in Exelon’s Consolidated Balance Sheets. For the years ended December 31, 2018, 2017 and 2016, Exelon settled restricted stock units with fair value totaling $106 million, $88 million and $68 million, respectively. At December 31, 2018, $38 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 2.5 years.

Performance Share Awards

Performance share awards are granted under the LTIP. The performance share awards are settled 50% in common stock and 50% in cash at the end of the three-year performance period, except for awards granted to vice presidents and higher officers that are settled 100% in cash if certain ownership requirements are satisfied.

The common stock portion of the performance share awards is considered an equity award and is valued based on Exelon's stock price on the grant date. The cash portion of the performance share awards is considered a liability award which is remeasured each reporting period based on Exelon’s current stock price. As the value of the common stock and cash portions of the awards are based on Exelon’s stock price during the performance period, coupled with changes in the total shareholder return modifier and expected payout of the award, the compensation costs are subject to volatility until payout is established.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Effective January 2017 for nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the straight-line method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

In 2016 and prior, for nonretirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method. For performance share awards granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period, which is the year of grant.

Exelon processes forfeitures as they occur for employees who do not complete the requisite service period.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2018:

Exelon

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2017[a]	2,956,966	$ 32.65
Granted	1,637,542	38.15
Change in performance	1,348,029	30.66
Vested	(848,574)	36.26
Forfeited	(50,467)	36.24
Undistributed vested awards [b]	(1,640,268)	33.38
Nonvested at December 31, 2018[a]	3,403,228	$ 33.13

(a) Excludes 3,586,259 and 2,723,440 of performance share awards issued to retirement-eligible employees as of December 31, 2018 and 2017, respectively, as they are fully vested.

(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2018.

The following table summarizes the weighted average grant date fair value and the fair value of performance share awards granted and settled for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018[a]	2017	2016
Weighted average grant date fair value (per share)	$38.15	$35.00	$28.85
Fair value of performance shares settled	61	72	45
Fair value of performance shares settled in cash	49	56	28

(a) As of December 31, 2018, $33 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 1.7 years.

For PHI, the weighted average grant date fair value (per share) of performance-based restricted stock awards was $26.10 for the year ended December 31, 2016. There were no time-based restricted stock awards granted for the year ended December 31, 2016. There were no time-based share settlements or performance-based share settlements for the year-ended December 31, 2016 or the predecessor period January 1, 2016 to March 23, 2016.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2018	2017
Current liabilities[(a)]	$ 135	$ 57
Deferred credits and other liabilities[(b)]	109	100
Common stock	26	26
Total	$ 270	$ 183

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

20. Earnings Per Share (Exelon)

Basic earnings per share is computed by dividing net income attributable to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share is computed by dividing net income attributable to common shareholders by the weighted average number of common shares outstanding, including the effect of issuing common stock assuming (i) stock options are exercised, and (ii) performance share awards and restricted stock awards are fully vested under the treasury stock method.

The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock awards on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2018	2017	2016
Net income attributable to common shareholders	$2,010	$3,786	$1,121
Weighted average common shares outstanding — basic	967	947	924
Assumed exercise and/or distributions of stock-based awards	2	2	3
Weighted average common shares outstanding — diluted	969	949	927

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 3 million in 2018, 8 million in 2017, and 12 million in 2016. There were no equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the years ended December 31, 2018, 2017, and 2016. See Note 18 — Shareholders' Equity for additional information regarding the equity units and equity forward units.

On June 1, 2017, Exelon settled the forward purchase contract, which was a component of the June 2014 equity units, through the issuance of approximately 33 million shares of Exelon common stock from treasury stock. The issuance of shares on June 1, 2017 triggered full dilution in the EPS calculation, which prior to settlement were included in the calculation of diluted EPS using the treasury stock method. See Note 18 — Shareholders' Equity for additional information regarding share repurchases.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

21. Changes in Accumulated Other Comprehensive Income (Exelon, Generation and PECO)

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the years ended December 31, 2018 and 2017:

For the Year Ended December 31, 2018	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains and (losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Investments Unconsolidated Affiliates	Total
Exelon[a]						
Beginning balance	$ (14)	$ 10	$ (2,998)	$ (23)	$ (1)	$ (3,026)
OCI before reclassifications	11	—	(143)	(10)	1	(141)
Amounts reclassified from AOCI[b]	1	—	181	—	—	182
Net current-period OCI	12	—	38	(10)	1	41
Impact of adoption of Recognition and Measurement of Financial Assets and Financial Liabilities standard[c]	—	(10)	—	—	—	(10)
Ending balance	$ (2)	$ —	$ (2,960)	$ (33)	$ —	$ (2,995)
Generation[a]						
Beginning balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
OCI before reclassifications	11	—	—	(10)	—	1
Amounts reclassified from AOCI[b]	1	—	—	—	—	1
Net current-period OCI	12	—	—	(10)	—	2
Impact of adoption of Recognition and Measurement of Financial Assets and Financial Liabilities standard[c]	—	(3)	—	—	—	(3)
Ending balance	$ (4)	$ —	$ —	$ (33)	$ (1)	$ (38)
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Impact of adoption of Recognition and Measurement of Financial Assets and Financial Liabilities standard[c]	—	(1)	—	—	—	(1)
Ending balance	$ —	$ —	$ —	$ —	$ —	$ —

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2017	Gains and (Losses) on Cash Flow Hedges	Unrealized Gains on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan items	Foreign Currency Items	AOCI of Investments Unconsolidated Affiliates	Total
Exelon[(a)]						
Beginning balance	$ (17)	$ 4	$ (2,610)	$ (30)	$ (7)	$ (2,660)
OCI before reclassifications	(1)	6	11	7	6	29
Amounts reclassified from AOCI[(b)]	4	—	140	—	—	144
Net current-period OCI	3	6	151	7	6	173
Impact of adoption of Reclassification of Certain Tax Effects from AOCI[(d)]	—	—	(539)	—	—	(539)
Ending balance	$ (14)	$ 10	$ (2,998)	$ (23)	$ (1)	$ (3,026)
Generation[(a)]						
Beginning balance	$ (19)	$ 2	$ —	$ (30)	$ (7)	$ (54)
OCI before reclassifications	(1)	1	—	7	6	13
Amounts reclassified from AOCI[(b)]	4	—	—	—	—	4
Net current-period OCI	3	1	—	7	6	17
Ending balance	$ (16)	$ 3	$ —	$ (23)	$ (1)	$ (37)
PECO[(a)]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[(b)]	—	—	—	—	—	—
Net current-period OCI	—	—	—	—	—	—
Ending balance	$ —	$ 1	$ —	$ —	$ —	$ 1

(a) All amounts are net of tax and noncontrolling interests. Amounts in parenthesis represent a decrease in AOCI.
(b) See next tables for details about these reclassifications.
(c) Exelon prospectively adopted the new standard Recognition and Measurement of Financial Assets and Financial Liabilities. The standard was adopted as of January 1, 2018, which resulted in an increase to Retained earnings and Accumulated other comprehensive loss of $10 million, $3 million and $1 million for Exelon, Generation and PECO, respectively. The amounts reclassified related to Rabbi Trusts. See Note 1 — Significant Accounting Policies for additional information.
(d) Exelon early adopted the new standard Reclassification of Certain Tax Effects from AOCI. The standard was adopted retrospectively as of December 31, 2017, which resulted in an increase to Exelon's Retained earnings and Accumulated other comprehensive loss of $539 million, primarily related to deferred income taxes associated with Exelon's pension and OPEB obligations. See Note 1 — Significant Accounting Policies for additional information.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

ComEd, PECO, BGE, PHI, Pepco, DPL and ACE did not have any reclassifications out of AOCI to Net income during the years ended December 31, 2018 and 2017. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the years ended December 31, 2018 and 2017:
For the Year Ended December 31, 2018

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ (1)	$ (1)	Interest expense
	(1)	(1)	Total before tax
	—	—	Tax benefit
	$ (1)	$ (1)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 90	$ —	
Actuarial losses[b]	(333)	—	
	(243)	—	Total before tax
	62	—	Tax benefit
	$ (181)	$ —	Net of tax
Total Reclassifications	$ (182)	$ (1)	Net of tax

421

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2017

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statement of Operations and Comprehensive Income
	Exelon	Generation	
Gains (Losses) on cash flow hedges			
Other cash flow hedges	$ (5)	$ (5)	Interest expense
	(5)	(5)	Total before tax
	1	1	Tax benefit
	$ (4)	$ (4)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 92	$ —	
Actuarial losses[b]	(324)	—	
	(232)	—	Total before tax
	92	—	Tax benefit
	$ (140)	$ —	Net of tax
Total Reclassifications	$ (144)	$ (4)	Net of tax

(a) Amounts in parenthesis represent a decrease in net income.
(b) This AOCI component is included in the computation of net periodic pension and OPEB cost. See Note 16 — Retirement Benefits for additional information.

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table presents income tax benefit (expense) allocated to each component of other comprehensive income (loss) during the years ended December 31, 2018, 2017 and 2016:

	For the Year Ended December 31,		
	2018	2017	2016
Exelon			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic benefit cost	$24	$36	$30
Actuarial loss reclassified to periodic benefit cost	(86)	(128)	(118)
Pension and non-pension postretirement benefit plans valuation adjustment	50	13	115
Change in unrealized gains on cash flow hedges	(5)	(7)	—
Change in unrealized gains (losses) on investments in unconsolidated affiliates	—	(3)	3
Change in unrealized gains on marketable securities	—	(1)	—
Total	$(17)	$(90)	$30
Generation			
Change in unrealized gains on cash flow hedges	$(4)	$(6)	$(2)
Change in unrealized gains (losses) on investments in unconsolidated affiliates	(1)	(3)	3
Change in unrealized gains on marketable securities	—	(1)	—
Total	$(5)	$(10)	$1

22. Commitments and Contingencies (All Registrants)

Commitments

Constellation Merger Commitments (Exelon and Generation). In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion.

The direct investment included the construction of a new 21-story headquarters building in Baltimore for Generation’s competitive energy business that was substantially complete in November 2016 and is now occupied by approximately 1,500 Exelon employees. Generation's investment in leasehold improvements totaled approximately $90 million. In addition, Generation entered into a 20-year operating lease as the primary lessee of the building.

The direct investment commitment also included $450 million to $500 million relating to Exelon and Generation’s development or assistance in the development of 285 - 300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years after the merger. The MDPSC order contemplated various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation have incurred $458 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 220 MW of the new generation commencing with commercial operations to date and an additional 10 MW commitment satisfied through a liquidated damages payment made in the fourth quarter of 2016. Additionally, during the fourth quarter of 2016, given continued declines in projected energy and capacity prices, Generation terminated rights to certain development projects originally intended to meet its remaining 55 MW commitment amount. The commitment is expected to be satisfied via payment of liquidated damages or execution of a third party PPA, rather than by Generation constructing renewable generating assets. As a result, Exelon and Generation

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

recorded a pre-tax $50 million loss contingency in Operating and maintenance expense in Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income for the year ended December 31, 2016. The remaining commitment is to be paid on or before January 15, 2023 unless the period is extended by consent of Exelon and the State of Maryland. As of December 31, 2018 and 2017, Exelon's and Generation's Consolidated Balance Sheets include a $50 million liability within Deferred credits and other liabilities for this remaining commitment.
Commercial Commitments (All Registrants). Exelon’s commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Letters of credit	$1,703	$1,394	$308	$ 1	$ —	$ —	$ —
Surety bonds(a)	1,402	1,331	33	38	—	—	—
Financing trust guarantees	378	—	—	—	—	—	378
Guaranteed lease residual values(b)	24	3	3	2	3	3	10
Total commercial commitments	$3,507	$2,728	$344	$ 41	$ 3	$ 3	$ 388

(a) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.
(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $61 million, $19 million of which is a guarantee by Pepco, $26 million by DPL and $16 million by ACE. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

Generation’s commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Letters of credit	$1,680	$1,380	$299	$ 1	$ —	$ —	$ —
Surety bonds(a)	1,220	1,201	19	—	—	—	—
Total commercial commitments	$2,900	$2,581	$318	$ 1	$ —	$ —	$ —

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

ComEd’s commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Letters of credit	$2	$2	$ —	$ —	$ —	$ —	$ —
Surety bonds(a)	12	10	—	2	—	—	—
Financing trust guarantees	200	—	—	—	—	—	200
Total commercial commitments	$214	$12	$ —	$ 2	$ —	$ —	$ 200

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

Table of Contents

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO's commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Surety bonds[a]	$ 9	$ 9	$ —	$ —	$ —	$ —	$ —
Financing trust guarantees	178	—	—	—	—	—	178
Total commercial commitments	$ 187	$ 9	$ —	$ —	$ —	$ —	$ 178

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

BGE's commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Letters of credit	$ 3	$ 2	$ 1	$ —	$ —	$ —	$ —
Surety bonds[a]	17	3	14	—	—	—	—
Total commercial commitments	$ 20	$ 5	$ 15	$ —	$ —	$ —	$ —

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

PHI commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Letters of credit	$ 8	$ —	$ 8	$ —	$ —	$ —	$ —
Surety bonds[a]	$ 41	$ 41	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	24	3	3	2	3	3	10
Total commercial commitments	$ 73	$ 44	$ 11	$ 2	$ 3	$ 3	$ 10

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

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $61 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and PHI believes the likelihood of payments being required under the guarantees is remote.

425

Combined Notes to Consolidated Financial Statements - (Continued)
(Dollars in millions, except per share data unless otherwise noted)

Pepco commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Letters of credit	$ 8	$—	$ 8	$ —	$ —	$ —	$ —
Surety bonds[a]	$ 33	$33	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	8	1	1	1	1	1	3
Total commercial commitments	$ 49	$34	$ 9	$ 1	$ 1	$ 1	$ 3

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

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $19 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and Pepco believes the likelihood of payments being required under the guarantees is remote.

DPL commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Surety bonds[a]	$ 5	$5	$ —	$ —	$ —	$ —	$ —
Guaranteed lease residual values[b]	10	1	1	1	1	1	5
Total commercial commitments	$ 15	$6	$ 1	$ 1	$ 1	$ 1	$ 5

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

(b) Represents the maximum potential obligation in the event that the fair value of certain leased equipment and fleet vehicles is zero at the end of the maximum lease term. The maximum lease term associated with these assets ranges from 3 to 8 years. The maximum potential obligation at the end of the minimum lease term would be $26 million. The minimum lease term associated with these assets ranges from 1 to 4 years. Historically, payments under the guarantees have not been made and DPL believes the likelihood of payments being required under the guarantees is remote.

ACE commercial commitments as of December 31, 2018, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2019	2020	2021	2022	2023	2024 and beyond
Surety bonds[a]	$ 3	$3	$ —	$ —	$ —	$	