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.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
Pepco Holdings or PHI	Pepco Holdings LLC (formerly Pepco Holdings, Inc.)
Pepco	Potomac Electric Power Company
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.

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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

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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

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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

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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

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FILING FORMAT

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

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.

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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		

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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.

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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.

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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

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(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).

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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

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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.

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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.

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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

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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

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(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

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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

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(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.

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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 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.

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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.

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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

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(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

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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 (SO_2), nitrogen oxides (NO_x), 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.

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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

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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

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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.

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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

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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

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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

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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

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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

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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

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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.

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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

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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

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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.

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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.

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Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could 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

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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.

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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.

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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

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.

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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

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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.

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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.

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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

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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-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

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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

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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.

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ITEM 2. PROPERTIES

Generation

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

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Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
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	

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Station[a]	Region	Location	No. of Units	Percent Owned[b]	Primary Fuel Type	Primary Dispatch Type[c]	Net Generation Capacity (MW)[d]	
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	

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Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
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	

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Station[(a)]	Region	Location	No. of Units	Percent Owned[(b)]	Primary Fuel Type	Primary Dispatch Type[(c)]	Net Generation Capacity (MW)[(d)]	
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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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.

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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

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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.

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ITEM 6. SELECTED FINANCIAL DATA

Exelon

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

	For the Years Ended December 31,				
(In millions, except per share data)	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.

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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

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(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

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	December 31,				
(In millions)	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.

	For the Years Ended December 31,				
(In millions)	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

	December 31,				
(In millions)	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

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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

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	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.

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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

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	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.

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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.

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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, 2018	Successor For the Years Ended December 31, 2017	Favorable (unfavorable) 2018 vs. 2017 variance	March 24 to December 31, 2016	Predecessor January 1 to March 23, 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;

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- 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;

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- 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:

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(All amounts after tax; in millions, except per share amounts)	For the Years Ended December 31, 2018	2018 Earnings per Diluted Share	2017	2017 Earnings per Diluted Share	2016	2016 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

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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.

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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.

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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

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

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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

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(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 %

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(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 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.

Income statement expense (pre-tax)	Actual 2018	Projected[(a)] 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,

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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

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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.

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- 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 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

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 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

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.

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.

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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.

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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

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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

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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)

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

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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.

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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	$—	$ —	$—	$—	$—	$—	$—

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(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

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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.

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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.

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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

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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.

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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;

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- 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

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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,