EXELON CORP
Form 10-K
February 14, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended December 31, 2013

OR

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

Commission File Number	Exact Name of Registrant as Specified in its Charter; State 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	23-2990190

	P.O. Box 805379 Chicago, Illinois 60680-5379 (312) 394-7398	
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

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

PECO ENERGY COMPANY:

Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York

BALTIMORE GAS AND ELECTRIC COMPANY:

6.20% Trust Preferred Securities ($25 liquidation amount per preferred security) issued by BGE Capital Trust II, fully and unconditionally guaranteed, by Baltimore Gas and Electric Company	New York

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

COMMONWEALTH EDISON COMPANY:

Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

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 ¨
Exelon Generation Company, LLC	Yes x No ¨
Commonwealth Edison Company	Yes x No ¨
PECO Energy Company	Yes x No ¨
Baltimore Gas and Electric Company	Yes x No ¨

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

Exelon Corporation	Yes ¨ No x
Exelon Generation Company, LLC	Yes ¨ No x
Commonwealth Edison Company	Yes ¨ No x
PECO Energy Company	Yes ¨ No x
Baltimore Gas and Electric Company	Yes ¨ No x

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

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

Indicate by check mark 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. ¨

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

	Large Accelerated	**Accelerated**	**Non-Accelerated**	**Small Reporting Company**
Exelon Corporation	ü			
Exelon Generation Company, LLC			ü	
Commonwealth Edison Company			ü	
PECO Energy Company			ü	
Baltimore Gas and Electric Company			ü	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Exelon Corporation	Yes ¨	No x
Exelon Generation Company, LLC	Yes ¨	No x
Commonwealth Edison Company	Yes ¨	No x
PECO Energy Company	Yes ¨	No x
Baltimore Gas and Electric Company	Yes ¨	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, 2013 was as follows:

Exelon Corporation Common Stock, without par value	$ 26,430,683,706
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

The number of shares outstanding of each registrant s common stock as of January 31, 2014 was as follows:

Exelon Corporation Common Stock, without par value	857,419,806
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,904
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company, without par value	1,000

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2014 Annual Meeting of

Shareholders and the Commonwealth Edison Company 2014 information statement are

incorporated by reference in Part III.

Exelon Generation Company, LLC, PECO Energy Company and Baltimore Gas and 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
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon s holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
ComEd Financing III	ComEd Financing III
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Energy Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
BGE Trust II	BGE Capital Trust II
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively
Other Terms and Abbreviations	
1998 restructuring settlement	PECO s 1998 settlement of its restructuring case mandated by the Competition Act
Act 11	Pennsylvania Act 11 of 2012
Act 129	Pennsylvania Act 129 of 2008
AEC	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
AEPS	Pennsylvania Alternative Energy Portfolio Standards
AEPS Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
AESO	Alberta Electric Systems Operator
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended

Other Terms and Abbreviations

Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CSAPR	Cross-State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy
DOJ	United States Department of Justice
DSP	Default Service Provider
DSP Program	Default Service Provider Program
EDF	Electricite de France SA
EE&C	Energy Efficiency and Conservation/Demand Response
EIMA	Illinois Energy Infrastructure Modernization Act
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act of 1974, as amended
EROA	Expected Rate of Return on Assets
ESPP	Employee Stock Purchase Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
Illinois Act	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
Illinois EPA	Illinois Environmental Protection Agency
Illinois Settlement Legislation	Legislation enacted in 2007 affecting electric utilities in Illinois
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIBOR	London Interbank Offered Rate
LILO	Lease-In, Lease-Out
LLRW	Low-Level Radioactive Waste

Other Terms and Abbreviations

LTIP	Long-Term Incentive Plan
MATS	U.S. EPA Mercury and Air Toxics Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MOPR	Minimum Offer Price Rule
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NJDEP	New Jersey Department of Environmental Protection
Non-Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
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
OCI	Other Comprehensive Income
OIESO	Ontario Independent Electricity System Operator
OPEB	Other Postretirement Employee Benefits
PA DEP	Pennsylvania Department of Environmental Protection
PAPUC	Pennsylvania Public Utility Commission
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
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal

Other Terms and Abbreviations

Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor s Ratings Services
SEC	United States Securities and Exchange Commission
Senate Bill 1	Maryland Senate Bill 1
SERC	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
SERP	Supplemental Employee Retirement Plan
SGIG	Smart Grid Investment Grant
SGIP	Smart Grid Initiative Program
SILO	Sale-In, Lease-Out
SMP	Smart Meter Program
SMPIP	Smart Meter Procurement and Installation Plan
SNF	Spent Nuclear Fuel
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas exploration and production activities
VIE	Variable Interest Entity
WECC	Western Electric Coordinating Council

FILING FORMAT

This combined Annual Report on Form 10-K is being filed separately by the Registrants. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Report are forward-looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrant discussed in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, (c) ITEM 8. Financial Statements and Supplementary Data: Note 22 and (d) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through Generation, in the energy generation business, and through ComEd, PECO and BGE, in the energy delivery businesses discussed below. Exelon s principal executive offices are located at 10 South Dearborn Street, Chicago, Illinois 60603, and its telephone number is 312-394-7398.

Generation

Generation s integrated business consists of its owned and contracted electric generating facilities and investments in generation ventures that are marketed through its leading customer-facing activities. These customer-facing activities include, wholesale energy marketing operations and its competitive retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions.

Generation was formed in 2000 as a Pennsylvania limited liability company. Generation began operations as a result of a corporate restructuring, effective January 1, 2001, in which Exelon separated its generation and other competitive businesses from its regulated energy delivery businesses at ComEd and PECO. Generation s principal executive offices are located at 300 Exelon Way, Kennett Square, Pennsylvania 19348, and its telephone number is 610-765-5959.

ComEd

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

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

PECO

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

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

BGE

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

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

Operating Segments

See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s operating segments.

Merger with Constellation Energy Group, Inc.

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation s interest in RF HoldCo LLC, which holds Constellation s interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon s interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the Constellation transaction.

Generation

Generation, one of the largest competitive electric generation companies in the United States as measured by owned and contracted MW, physically delivers and markets power across multiple geographic regions through its customer-facing business, Constellation. 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. Generation operates as an integrated business, leveraging its owned and contracted electric generation capacity to market and sell power to wholesale and retail customers. Generation s customers include distribution utilities, municipalities, cooperatives, financial institutions, and commercial, industrial, governmental, and residential customers in competitive markets. Generation also sells natural gas and renewable energy and other energy-related products and services, and engages in natural gas exploration and production activities.

Generation is a public utility under the Federal Power Act and is subject to FERC s exclusive ratemaking jurisdiction over wholesale sales of electricity and the transmission of electricity in interstate commerce. Under the Federal Power Act, FERC has the authority to grant or deny market-based rates for sales of energy, capacity and ancillary services to ensure that such sales are just and reasonable. FERC s jurisdiction over ratemaking also includes the authority to suspend the market-based rates of utilities (including Generation, which is a public utility as FERC defines that term) and set cost-based rates should FERC find that its previous grant of market-based rates authority is no longer just and reasonable. Other matters subject to FERC jurisdiction include, but are not limited to, third-party financings; review of mergers; dispositions of jurisdictional facilities and acquisitions of securities of

another public utility or an existing operational generating facility; affiliate transactions; intercompany financings and cash management arrangements; certain internal corporate reorganizations; and certain holding company acquisitions of public utility and holding company securities. Additionally, ERCOT is not subject to regulation by FERC but performs a similar function in Texas to that performed by RTOs in markets regulated by FERC. Specific operations of Generation are also subject to the jurisdiction of various other Federal, state, regional and local agencies, including the NRC and Federal and state environmental protection agencies. Additionally, Generation is subject to mandatory reliability standards promulgated by the NERC, with the approval of FERC.

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

Significant Acquisitions

Antelope Valley Solar Ranch One. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation s renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of all of the equity interests of Wolf Hollow, LLC (Wolf Hollow), a combined-cycle natural gas-fired power plant in north Texas, for a purchase price of $311 million which increased Generation s owned capacity within the ERCOT power market by 720 MWs.

See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information on the above acquisitions.

Significant Dispositions

Maryland Clean Coal Stations. On November 30, 2012, a subsidiary of Generation sold the Brandon Shores generating station and H.A. Wagner generating station in Anne Arundel County, Maryland, and the C.P. Crane generating station in Baltimore County, Maryland to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC to comply with certain of the regulatory approvals required by the merger, for net proceeds of approximately $371 million, which resulted in a pre-tax loss of $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Generating Resources

At December 31, 2013, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [(a)]	
Nuclear	17,263
Fossil	12,165
Renewable (including Hydroelectric) [(b)]	3,710
Owned generation assets	33,138
Long-term power purchase contracts [(c)]	9,426
Investment in CENG [(d)]	1,999
Total generating resources	44,563

(a) See Fuel for sources of fuels used in electric generation.
(b) Includes equity method investment in certain generating facilities.
(c) Excludes contracts with CENG. See Long-Term Power Purchase Contracts table in this section for additional information.
(d) Generation owns a 50.01% interest in CENG, a joint venture with EDF. See ITEM 2. PROPERTIES Generation and Note 25 Related Party Transactions of the Combined Notes to Consolidated Financial Statements for additional information.

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

Mid-Atlantic represents operations in the eastern half of PJM, which includes Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of North Carolina (approximately 37% of capacity).

Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the United States footprint of MISO excluding MISO s Southern Region, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, and the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM; and parts of Montana, Missouri and Kentucky (approximately 34% of capacity).

New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont (approximately 8% of capacity).

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

ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas (approximately 12% of capacity).

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

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,263 MW of capacity. Generation wholly owns all of its nuclear generating stations, except for Quad Cities Generating Station (75% ownership), Peach Bottom Generating Station (50% ownership) and Salem Generating Station (Salem) (42.59% ownership), which are consolidated on Exelon s financial statements relative to its proportionate ownership interest in each unit. 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 2013 and 2012, electric supply (in GWh) generated from the nuclear generating facilities was 57% and 53%, respectively, of Generation s total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. The majority of this output was dispatched to support Generation s wholesale and retail power marketing activities. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation s electric supply sources.

Constellation Energy Nuclear Group, Inc.

Generation also 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 and operates a total of five nuclear generating facilities on three sites, Calvert Cliffs, Ginna and Nine Mile Point. CENG s ownership share in the total capacity of these units is 3,998 MW. See ITEM 2. PROPERTIES for additional information on these sites.

On July 29, 2013, Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. The Master Agreement contemplates that the parties will execute a series of additional agreements at a closing that will occur following the receipt of regulatory approvals and the satisfaction of other customary closing conditions. Exelon currently expects that the closing will occur early in the second quarter of 2014.

At the closing, Generation, CENG and subsidiaries of CENG will execute a Nuclear Operating Services Agreement pursuant to which Generation will operate the CENG nuclear generation fleet owned by CENG subsidiaries and provide corporate and administrative services for the remaining life of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to EDFI s rights as a member of CENG. CENG will reimburse Generation for its direct and allocated costs for such services. The Nuclear Operating Services Agreement will replace the SSA. At the closing, Nine Mile Point Nuclear Station, a subsidiary of CENG, will also assign to Generation its obligations as Operator of Nine Mile Point Unit 2 under an operating agreement with the co-owner. In addition, at the closing the PSAA will be amended and extended until the complete and permanent cessation of operation of the CENG generation plants.

At closing, Generation will make a $400 million loan to CENG bearing interest at 5.25% per annum, payable out of specified available cash flows of CENG and, in any event, payable upon settlement of the Put Option Agreement discussed below, if the put option is exercised, or payable upon the maturity date of the note (which will be 20 years from the closing), whichever occurs first. Immediately following receipt of the proceeds of such loan, CENG will make a $400 million special distribution to EDFI. The parties will also execute a Fourth Amended and Restated Operating Agreement for CENG, pursuant to which, among other things, CENG will commit to make preferred distributions to Generation (after repayment of the $400 million loan) quarterly out of specified available cash flows, until Generation has received aggregate distributions of $400 million plus a return of 8.5% per annum from the date of the special distribution to EDFI.

Generation and EDFI will also enter into a Put Option Agreement at closing pursuant to which EDFI will have the option, exercisable beginning in 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. The beginning of the exercise period will be accelerated if

Exelon s affiliates cease to own a majority of CENG and exercise a related right to terminate the Nuclear Operating Services Agreement. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Generation will execute an Indemnity Agreement pursuant to which Generation will indemnify EDF and its affiliates against third party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon will guarantee Generation s obligations under this indemnity.

CENG owns 100% of four nuclear units in Maryland and New York and 82% of Nine Mile Point Unit 2 in New York. Generation currently has an agreement under which it is purchasing 85% of the nuclear plant output owned by CENG that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the nuclear plant output owned by CENG, and EDF will purchase on a unit contingent basis 49.99% of the nuclear plant output owned by CENG (EDF PPA). This agreement will continue to be effective and is not affected by the Master Agreement, except that if the put option under the Master Agreement is exercised, then the EDF PPA would transfer to Generation upon the completion of the Put Option Agreement transaction.

Currently, Exelon and Generation account for its investment in CENG under the equity method of accounting. The transfer of the operational control to Exelon and Generation will result in Exelon and Generation being required to consolidate the financial position and results of operations of CENG. When that accounting change occurs, Exelon and Generation will derecognize its equity method investment in CENG and will record all assets, liabilities and the non-controlling interest in CENG at fair value on Exelon and Generation s balance sheets. Any difference between the former carrying value and newly recorded fair value at that date will be recognized as a gain or loss upon consolidation, which could be material to Exelon s and Generation s results of operations. See Note 5 Investment in CENG of the Combined Notes to Consolidated Financial Statements for additional information regarding CENG.

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

During 2013 and 2012, the nuclear generating facilities operated by Generation achieved capacity factors of 94.1% and 92.7%, respectively. 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 marketing and trading activities. During scheduled refueling outages, Generation performs maintenance and equipment upgrades in order to minimize the occurrence of unplanned outages and to maintain safe, reliable operations.

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

Regulation of Nuclear Power Generation. Generation is subject to the jurisdiction of the NRC with respect to the operation of its nuclear generating stations, including the licensing for operation of each unit. The NRC subjects nuclear generating stations to continuing review and regulation covering, among other things, operations, maintenance, emergency planning, security and environmental and radiological aspects of those stations. As part of its reactor oversight process, the NRC continuously

assesses unit performance indicators and inspection results, and communicates its assessment on a semi-annual basis. As of December 31, 2013, the NRC categorized Dresden units 2 and 3, LaSalle unit 2, and Clinton in the Regulatory Response Column, which is the second highest of five performance bands. All other units operated by Generation are categorized in the Licensee Response Column as of December 31, 2013, which is the highest performance band. On January 1, 2014, Dresden units 2 and 3 returned to the Licensee Response Column. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in regulations by the NRC may require a substantial increase in capital expenditures for nuclear generating facilities and/or increased operating costs of nuclear generating units.

On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force s report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. For additional information on the NRC actions related to the Japan Earthquake and Tsunami and the industry s response, see ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Executive Overview.

Licenses. Generation has 40-year operating licenses from the NRC for each of its nuclear units and has received 20-year operating license renewals for Peach Bottom Units 2 and 3, Dresden Units 2 and 3, Quad Cities Units 1 and 2, Oyster Creek and Three Mile Island Unit 1. Additionally, PSEG has 40-year operating licenses from the NRC and has received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. The following table summarizes the current operating license expiration dates for Generation s nuclear facilities in service:

Station	Unit	In-Service Date [(a)]	Current License Expiration
Braidwood [(b)]	1	1988	2026
	2	1988	2027
Byron [(b)]	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden [(c)]	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick [(d)]	1	1986	2024
	2	1990	2029
Oyster Creek [(c)(e)]	1	1969	2029
Peach Bottom [(c)]	2	1974	2033
	3	1974	2034
Quad Cities [(c)]	1	1973	2032
	2	1973	2032
Salem [(c)]	1	1977	2036
	2	1981	2040
Three Mile Island [(c)]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) On May 29, 2013, Generation submitted applications to the NRC to extend the operating licenses of Braidwood Units 1 and 2 and Byron Units 1 and 2 by 20 years.
(c) Stations for which the NRC has issued a renewed operating licenses.
(d) In June 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(e) In December 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Generation expects to apply for and obtain approval of license renewals for the remaining nuclear units. The operating license renewal process takes approximately four to five years from the commencement of the renewal process until completion of the NRC s review. The NRC review process takes approximately two years from the docketing of an application. Each requested license renewal is expected to be for 20 years beyond the original license expiration. Depreciation provisions are based on the estimated useful lives of the stations, which reflect the actual and assumed renewal of operating licenses for all of Generation s operating nuclear generating stations except for Oyster Creek.

In August 2012, Generation entered into an operating services agreement with the Omaha Public Power District (OPPD) to provide operational and managerial support services for the Fort Calhoun Station and a licensing agreement for use of the Exelon Nuclear Management Model. The terms for both agreements are 20 years. OPPD will continue to own the plant and remain the NRC licensee.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Nuclear Waste 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 in on-site 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, 2013, Generation had approximately 59,900 SNF assemblies (14,400 tons) stored on site in SNF pools or dry cask storage (this includes SNF assemblies at Zion Station, for which Generation retains ownership even though the responsibility for decommissioning Zion Station has been assumed by another party; see Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). All currently operating Generation-owned nuclear sites have on-site dry cask storage, except for Clinton and Three Mile Island. Clinton and Three Mile Island will currently lose full core reserve, which is when the on-site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core, in 2015 and 2023, respectively. Dry cask storage will be in operation at Clinton and is expected to be in operation at Three Mile Island prior to the closing of their respective on-site storage pools. 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 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 is currently utilizing on-site storage capacity at its nuclear generation stations for limited amounts of LLRW and has been shipping its Class A LLRW, which represent 93% of LLRW generated at its stations, to disposal facilities in Utah and South Carolina. The disposal facility in South Carolina at present is only receiving LLRW from LLRW generators in South Carolina, New Jersey (which includes Oyster Creek and Salem), and Connecticut. Generation has received NRC approval for its Peach Bottom and LaSalle stations that will allow storage at these sites of LLRW from its remaining stations with limited capacity. Generation now has enough storage capacity to store all Class B and C LLRW for the life of all stations in Generation s nuclear fleet. During 2012, Generation entered into a six year contract to ship Class B and Class C LLRW to Texas. The terms of the agreement will provide for disposal of all current Class B and Class C LLRW stored at the stations, as well as the waste generated during the term of the agreement. Although Texas started accepting waste for disposal in 2012, the Texas site is curie limited (3.9 million curies for 15 years). With this limit, the annual facility volume will not match industry production of activated hardware, and on-site storage is expected to be required for the Generation boiling water reactors. Generation continues to pursue alternative disposal strategies for LLRW, including an LLRW reduction program to minimize cost impacts and on-site storage.

Nuclear Insurance. Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See Nuclear Insurance within Note 22 of the Combined Notes to Consolidated Financial Statements for details.

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

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning, Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Notes 3, 11 and 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Generation s NDT funds and its decommissioning obligations.

Dresden Unit 1 and Peach Bottom Unit 1 have ceased power generation. SNF at Dresden Unit 1 is currently being stored in dry cask storage until a permanent repository under the NWPA is completed. All SNF for Peach Bottom Unit 1, which ceased operation in 1974, has been removed from the site and the SNF pool is drained and decontaminated. Generation s estimated ARO liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2013 was $208 million and $114 million, respectively. As of December 31, 2013, NDT funds set aside to pay for these obligations were $436 million.

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

On September 1, 2010, Generation and EnergySolutions completed the transactions contemplated by the ASA. Specifically, Generation transferred to ZionSolutions substantially all of the assets (other than land) associated with Zion Station, including assets held in related NDT funds. In consideration for Generation s transfer of those assets, ZionSolutions assumed decommissioning and other liabilities, excluding the obligation to dispose of SNF, associated with Zion Station. Pursuant to the ASA, ZionSolutions will periodically request reimbursement from the Zion Station-related NDT funds for costs incurred related to the decommissioning efforts at Zion Station. However, ZionSolutions is subject to certain restrictions on its ability to request reimbursement; specifically, if certain milestones as defined in the ASA are not met, all or a portion of requested reimbursements shall be deferred until such milestones are met. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning and see Note 2 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)

Generation has ownership interests in 15,875 MW of capacity in fossil and renewable generating facilities currently in service. Generation wholly owns all of its fossil and renewable generating stations, with the exception of: (1) jointly owned facilities that include Keystone, Conemaugh, and Wyman; (2) ownership interests through equity method investments in Colver, Malacha, Safe Harbor, and Sunnyside; and (3) certain wind project entities with minority interest owners, see Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on these wind project entities. Generation s fossil and renewable generating stations are all operated by Generation, with the exception of Colver, Conemaugh, Keystone, LaPorte, Malacha, Safe Harbor, Sunnyside and Wyman, which are operated by third parties. In 2013 and 2012, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 15% and 12%, 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 Generation and ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview for additional information on Generation Renewable Development.

Licenses. Fossil and renewable generation plants are generally not licensed, and, therefore, the decision on when to retire plants is, fundamentally, a commercial one. FERC has the exclusive authority to license most non-Federal hydropower projects located on navigable waterways or Federal lands, or connected to the interstate electric grid. On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Muddy Run Pumped Storage Project and the Conowingo Hydroelectric Project, respectively. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run s current license on August 31, 2014, and the expiration of Conowingo s license on September 1, 2014. However, the stations will continue to operate under annual licenses until FERC takes action on the 46-year license applications. Refer to Note 3 Regulatory Matters for additional information.

Insurance. Generation maintains business interruption insurance for its renewable projects, and delay in start-up insurance for its renewable projects currently under construction. Generation does not purchase business interruption insurance for its wholly owned fossil and hydroelectric operations. 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 financial condition and their results of operations and cash flows. For information regarding property insurance, see ITEM 2. PROPERTIES Generation.

Long-Term Power Purchase Contracts

In addition to energy produced by owned generation assets, Generation sources electricity and other related output from plants it does not own under long-term contracts. The following tables summarize Generation s long-term contracts to purchase unit-specific physical power with an original term in excess of one year in duration, by region, in effect as of December 31, 2013:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic [a]	16	2016 - 2032	799
Midwest	7	2015 - 2022	1,734
New England	14	2014 - 2020	1,291
ERCOT	5	2014 - 2026	1,489
Other Regions	11	2014 - 2030	4,113
Total	53		9,426

	2014	2015	2016	2017	2018
Capacity Expiring (MW)	1,300	1,705	651	1,337	100

(a) Excludes contracts with CENG.

Fuel

The following table shows sources of electric supply in GWh for 2013 and 2012:

	Source of Electric Supply [(a)]	
	2013	**2012**
Nuclear	142,126	139,862
Purchases non-trading portfolio[(b)]	69,791	91,994
Fossil	30,785	27,760
Renewable	6,420	4,079
Total supply	249,122	263,695

(a) Represents Generation s proportionate share of the output of its generating plants.
(b) Includes purchases pursuant to Generation s PPA with CENG. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

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

The cycle of production and utilization of nuclear fuel includes the mining and milling of uranium ore into uranium concentrates, the conversion of uranium concentrates to uranium hexafluoride, the enrichment of the uranium hexafluoride and the fabrication of fuel assemblies. Generation has uranium concentrate inventory and supply contracts sufficient to meet all of its uranium concentrate requirements through 2016. Generation s contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2020. All of Generation s enrichment requirements have been contracted through 2018. Contracts for fuel fabrication have been obtained through 2018. Generation does not anticipate difficulty in obtaining the necessary uranium concentrates or conversion, enrichment or fabrication services to meet the nuclear fuel requirements of its nuclear units.

Natural gas is procured through long-term and short-term contracts, as well as spot-market purchases. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk, using both over-the-counter and exchange-traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Marketing

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

Generation s purchases may be for more than the energy demanded by Generation s customers. Generation then sells this open position, along with capacity not used to meet customer demand, in the wholesale electricity markets. Where necessary, Generation also purchases transmission service to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs in markets without an organized RTO. Generation also incorporates contingencies into its planning for extreme weather conditions, including potentially reserving capacity to meet summer loads at levels representative of warmer-than-normal weather conditions. Generation actively manages these physical and contractual assets in order to derive incremental value. Additionally, Generation is involved in the development, exploration, and harvesting of oil, natural gas and natural gas liquids properties.

Price Supply Risk Management

Generation also manages the price and supply risks for energy and fuel associated with generation assets and the risks of power marketing activities. Generation implements a three-year ratable sales plan to align its hedging strategy with its financial objectives. Generation also enters into transactions that are outside of this ratable sales plan. Generation is exposed to relatively greater commodity price risk in 2014 and beyond for which a larger portion of its electricity portfolio may be unhedged. Generation has been and will continue to be proactive in using hedging strategies to mitigate this risk in subsequent years. As of December 31, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity, including purchased power from CENG. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts, including sales to ComEd, PECO and BGE to serve their retail load. A portion of Generation s hedging strategy may be implemented through the use of fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. 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 trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop-loss and value-at-risk limits, to manage exposure to market risk. Additionally, the corporate risk management group and Exelon s RMC monitor the financial risks of the wholesale and retail power marketing activities. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for additional information.

At December 31, 2013, Generation s short and long-term commitments relating to the purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases (a)	REC Purchases (b)	Transmission Rights Purchases (c)	Purchased Energy from CENG	Total
2014	$ 412	$ 117	$ 25	$ 824	$ 1,378
2015	367	110	13		490
2016	284	76	2		362
2017	223	25	2		250
2018	112	3	2		117
Thereafter	414	3	32		449
Total	$ 1,812	$ 334	$ 76	$ 824	$ 3,046

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation s expected payments under these arrangements at December 31, 2013, net of fixed capacity payments expected to be received by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. Expected payments include certain fixed capacity charges which may be reduced on plant availability.
(b) The table excludes renewable energy purchases that are contingent in nature.
(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

As part of reaching a comprehensive agreement with EDF in October 2010, the existing power purchase agreements with CENG were modified to be unit-contingent through the end of their original term in 2014. Under these agreements Generation purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties. CENG has the ability to fix the energy price on a forward basis by entering into monthly energy hedge transactions for a portion of the future sale, while any unhedged portions will be provided at market prices by default. Additionally, beginning in 2015 and continuing to the end of the life of the respective plants, Generation agreed to purchase 50.01% of the nuclear plant output owned by CENG at market prices. This purchase agreement will continue to be effective under the Master Agreement discussed above, except that if the put option under the Master Agreement is exercised, then the EDF PPA will be transferred to Generation upon the completion of the Put Option Agreement transaction. Generation discloses in the table above commitments to purchase from CENG at fixed prices. All commitments to purchase from CENG at market prices, which include all purchases subsequent to December 31, 2014, are excluded from the table. Generation continues to own a 50.01% membership interest in CENG that is accounted for as an equity method investment. See Note 25 of the Combined Notes to Consolidated Financial Statements for more details on this arrangement.

Capital Expenditures

Generation s business is capital intensive and requires significant investments in nuclear fuel and energy generation assets and in other internal infrastructure projects. Generation s estimated capital expenditures for 2014 are as follows:

(in millions)	
Nuclear fuel (a)	$ 900
Production plant	900
Renewable energy projects	300
Uprates	150
Maryland commitments	100
Other	50
Total	$ 2,400

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

ComEd

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

ComEd s retail service territory has an area of approximately 11,400 square miles and an estimated population of 9 million. The service territory includes the City of Chicago, an area of about 225 square miles with an estimated population of 2.7 million. ComEd has approximately 3.8 million customers.

ComEd s franchises are sufficient to permit it to engage in the business it now conducts. ComEd s franchise rights are generally nonexclusive rights documented in agreements and, in some cases, certificates of public convenience issued by the ICC. With few exceptions, the franchise rights have stated expiration dates ranging from 2014 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd s kWh deliveries and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. ComEd s highest peak load occurred on July 20, 2011, and was 23,753 MWs; its highest peak load during a winter season occurred on January 6, 2014, and was 16,514 MWs.

Retail Electric Services

Electric revenues and purchased power expense are affected by fluctuations in customers purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from a competitive electric generation supplier. The customers choice activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense. ComEd s cost of electric supply is passed without markup directly through to those customers not served by a competitive electric generation supplier and those rates are subject to adjustment monthly to recover or refund the difference between ComEd s actual cost of electricity delivered and the amount included in rates. For those customers that choose a competitive electric generation supplier, ComEd acts as the billing agent but does not record revenues or expenses related to the electric supply. ComEd remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for additional information on customer switching to competitive electric generation suppliers, and Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electricity procurement process and for additional information.

Under Illinois law, ComEd is required to deliver electricity to all customers. ComEd s obligation to provide generation supply service, which is referred to as a POLR obligation, primarily varies by customer size. ComEd s obligation to provide such service to residential customers and other small customers with demands of under 100 kWs continues for all customers who do not choose a competitive electric generation supplier or who choose to return to ComEd after taking service from a competitive electric generation supplier. ComEd does not have a fixed-price generation supply service obligation to most of its largest customers with demands of 100 kWs or greater, as this group of customers has previously been declared competitive. Customers with competitive declarations may still purchase power and energy from ComEd, but only at hourly market prices.

Energy Infrastructure Modernization Act (EIMA). Since 2011, ComEd s distribution rates are established through a performance-based rate formula pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. In addition, as long as ComEd is subject to EIMA, ComEd will fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates.

ComEd files an annual reconciliation of the revenue requirement in effect in a given year to reflect the actual costs that the ICC determines are prudently and reasonably incurred for such year. Under the terms of EIMA, ComEd s target rate of return on common equity is subject to reduction if ComEd does not deliver the reliability and customer service benefits, as defined, it has committed to over the ten-year life of the investment program. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Electric Distribution Rate Cases. The ICC issued an order in ComEd s 2007 electric distribution rate case (2007 Rate Case) approving a $274 million increase in ComEd s annual delivery services revenue requirement, which became effective in September 2008. In the order, the ICC authorized a 10.3% rate of return on common equity. On February 23, 2012, the ICC issued an order in the remand proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). On September 27, 2013, the Court ruled against ComEd on the accumulated depreciation issue and affirmed that ComEd owes a refund to customers of $37 million. As of December 31, 2013, and December 31, 2012, ComEd was fully reserved for this liability. ComEd will not seek rehearing or appeal on this matter and is working with the ICC on the process and timing for a refund to customers.

On May 24, 2011, the ICC issued an order in ComEd s 2010 electric distribution rate case (2010 Rate Case), which became effective on June 1, 2011. The order approved a $143 million increase to ComEd s annual delivery service revenue requirement and a 10.5% rate of return on common equity. The order has been appealed to the Court by several parties. On May 16, 2013, the Court dismissed as moot the appeals of the ICC s order in the 2010 Rate Case as ComEd now recovers distribution costs under EIMA through a pre-established formula rate tariff. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electric distribution rate cases.

Procurement-Related Proceedings. Since June 2009, the IPA designs, and the ICC approves, an electricity supply portfolio for ComEd and the IPA administers a competitive process under which ComEd procures its electricity supply from various suppliers, including Generation. As required by EIMA, in February 2012 the IPA completed procurement events for energy and REC requirements for the June 2013 through December 2017 period. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s procurement plans. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s energy commitments.

Continuous Power Interruption. The Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd s case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law. See Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC, which was approved by the ICC on June 22, 2012, with certain modifications. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing and filed a revised AMI deployment plan with the ICC. On December 5, 2012, the ICC approved ComEd s revised AMI deployment plan. On June 5, 2013, the ICC issued an interim Order approving ComEd s accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

Energy Efficiency Programs. As a result of the Illinois Settlement Legislation, electric utilities in Illinois are required to include cost-effective energy efficiency resources in their plans to meet an incremental annual program energy savings requirement of 0.2% of energy delivered to retail customers for the year ended June 1, 2009, which increases annually to 2.0% of energy delivered in the year commencing June 1, 2015 and each year thereafter. Additionally, during the ten-year period that began June 1, 2008, electric utilities must implement cost-effective demand response measures to reduce peak demand by 0.1% over the prior year for eligible retail customers. The energy efficiency and demand response goals are subject to rate impact caps each year. Utilities are allowed recovery of costs for energy efficiency and demand response programs, subject to approval by the ICC. In December 2010, the ICC approved ComEd s second three-year Energy Efficiency and Demand Response Plan covering the period June 2011 through May 2014. The plans are designed to meet the Illinois Settlement Legislation s energy efficiency and demand response goals through May 2014, including reductions in delivered energy to all retail customers and in the peak demand of eligible retail customers.

EIMA provides for additional energy efficiency in Illinois. Starting in the June 2013 May 2014 period and occurring annually thereafter, as part of the IPA procurement plan, ComEd is to include cost-effective expansion of current energy efficiency programs, any additional new cost-effective program and/or third-party energy efficiency programs that are identified through a request for proposal (RFP) process. All cost-effective energy efficiency programs are included in the IPA procurement plan for consideration of implementation. While these programs are monitored separately from the Energy Efficiency Portfolio Standard (EEPS), funds for both the EEPS portfolio and IPA energy efficiency programs are collected under the same rider.

Construction Budget

ComEd s business is capital intensive and requires significant investments primarily in energy transmission and distribution facilities, to ensure the adequate capacity, reliability and efficiency of its system. Based on PJM s RTEP, ComEd has various construction commitments, as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. ComEd s most recent estimate of capital expenditures for electric plant additions and improvements for 2014 is $1,775 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and

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

PECO s combined electric and natural gas retail service territory has an area of approximately 2,100 square miles and an estimated population of 4.0 million. PECO provides electric distribution service in an area of approximately 1,900 square miles, with a population of approximately 3.9 million, including approximately 1.5 million in the City of Philadelphia. PECO provides natural gas distribution service in an area of approximately 1,900 square miles in southeastern Pennsylvania adjacent to the City of Philadelphia, with a population of approximately 2.4 million. PECO delivers electricity to approximately 1.6 million customers and natural gas to approximately 501,000 customers.

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

PECO s kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. PECO s highest peak load occurred on July 22, 2011 and was 8,983 MW; its highest peak load during winter months occurred on January 7, 2014 and was 7,148 MW.

PECO s natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. PECO s highest daily natural gas send out occurred on January 7, 2014 and was 760 mmcf.

Retail Electric Services

PECO s retail electric sales and distribution service revenues are derived pursuant to rates regulated by the PAPUC. Pennsylvania permits competition by competitive electric generation suppliers for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2013, there were 87 competitive electric generation suppliers serving PECO customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was 531,500 representing approximately 34% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 68% of PECO s retail kWh sales for the year ended December 31, 2013. Customers that choose a competitive electric generation supplier are not subject to rates for PECO s electric supply procurement costs and retail transmission service charges. PECO presents on customer bills its electric supply Price to Compare, which is updated quarterly, to assist customers with the evaluation of offers from competitive electric generation suppliers.

Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has no impact on electric revenue net of purchased power expense or PECO s financial position. PECO s cost of electric supply is passed directly through to default service

customers without markup and those rates are subject to adjustment at least quarterly to recover or refund the difference between PECO s actual cost of electricity delivered and the amount included in rates through the GSA. For those customers that choose a competitive electric generation supplier, PECO acts as the billing agent but does not record revenues or purchase power expense related to this electric supply. PECO remains the distribution service provider for all customers in its service territory and charges a regulated rate for distribution service.

Procurement Proceedings. PECO s electric supply for its customers is procured through contracts executed in accordance with its PAPUC-approved DSP Programs. PECO entered into contracts with PAPUC-approved bidders, including Generation, as part of its DSP I competitive procurements conducted since June 2009 for its default electric supply beginning January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. In September 2012, PECO completed its last competitive procurement for electric supply under its first DSP Program, which expired on May 31, 2013.

On October 12, 2012, the PAPUC approved PECO s second DSP Program, which was filed with the PAPUC in January 2012. The plan outlines how PECO is purchasing electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO is procuring electric supply through five competitive procurements for fixed price full requirements contracts of two years or less for the residential and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in June 2013. In September 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes that began in December 2013. In January 2014, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small, medium and large commercial classes that will begin in June 2014. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Statement of Operations and Comprehensive Income.

The second DSP Program also includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from competitive electric generation suppliers beginning April 1, 2014. On May 1, 2013, PECO filed a Petition for Approval of its CAP Shopping Plan with the PAPUC, which the PAPUC granted and denied in part on January 9, 2014. PECO and other parties to the proceeding filed petitions for reconsideration of the Commission s decision on February 10, 2014, and these petitions are currently pending before the PAPUC.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter, Smart Grid and Energy Efficiency Programs

Smart Meter and Smart Grid Programs. In April 2010, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan, which was filed in accordance with the requirements of Act 129. Also, in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, PECO has been awarded $200 million, the maximum grant allowable under the program, for its SGIG project Smart Future Greater Philadelphia. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. On May 31, 2013, PECO and interested parties filed a Joint Petition for Settlement of the universal deployment plan with the PAPUC, which was approved without modification on August 15, 2013. In total, PECO currently expects to spend up to $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, before considering the $200 million SGIG.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Energy Efficiency Programs. PECO s PAPUC-approved Phase I EE&C plan had a four-year term that began on June 1, 2009 and concluded on May 31, 2013. The Phase I Plan sets forth how PECO would meet the required reduction targets established by Act 129 s EE&C provisions, which included a 3% reduction in electric consumption in PECO s service territory and a 4.5% reduction in PECO s annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report was filed with the PAPUC on November 15, 2013.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129 s EE&C programs, which went into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until late 2013. On February 28, 2013, the PAPUC approved PECO s three-year EE&C Phase II plan that was filed with the PAPUC on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 1,125,852 MWh in its service territory for the period June 1, 2013 through May 31, 2016.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO s natural gas sales and distribution service revenues are derived through natural gas deliveries at rates regulated by the PAPUC. PECO s purchased natural gas cost rates, which represent a significant portion of total rates, are subject to quarterly adjustments designed to recover or refund the difference between the actual cost of purchased natural gas and the amount included in rates without markup through the PGC.

PECO s natural gas customers have the right to choose their natural gas suppliers or to purchase their gas supply from PECO at cost. At December 31, 2013, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 66,400, representing approximately 13% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 19% of PECO s mmcf sales for the year ended December 31, 2013. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

Procurement Proceedings. PECO s natural gas supply is purchased from a number of suppliers primarily under long-term firm transportation contracts for terms of up to three years in accordance with its annual PAPUC PGC settlement. PECO s aggregate annual firm supply under these firm transportation contracts is 34 million dekatherms. Peak natural gas is provided by PECO s liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 21 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO s 2013-2014 heating season planned supplies.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Construction Budget

PECO s business is capital intensive and requires significant investments primarily in electric transmission and electric and natural gas distribution facilities to ensure the adequate capacity, reliability and efficiency of its system. PECO, as a transmission facilities owner, has various construction commitments under PJM s RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. PECO s most recent estimate of capital expenditures for plant additions and improvements for 2014 is $625 million, which includes RTEP projects and capital expenditures related to the smart meter and smart grid project net of expected SGIG DOE reimbursements.

BGE

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

BGE serves an estimated population of 2.8 million in its 2,300 square mile combined electric and gas retail service territory. BGE provides electric distribution service in an area of approximately 2,300 square miles and gas distribution service in an area of approximately 800 square miles, both with a population of approximately 2.8 million, including approximately 621,000 in the City of Baltimore. BGE delivers electricity to approximately 1.2 million customers and natural gas to approximately 655,000 customers.

BGE has the necessary authorizations to provide regulated electric and natural gas distribution services in the various municipalities and territories in which it now supplies such services. With respect to electric distribution service, BGE s authorizations consist of charter rights, a state-wide franchise grant and a franchise grant from the City of Baltimore. The franchise rights are not exclusive and are perpetual. With respect to natural gas distribution service, BGE s authorizations consist of charter rights, a perpetual state-wide franchise grant, and franchises granted by all the municipalities and/or governmental bodies in which BGE now supplies services. The franchise grants are not exclusive; some are perpetual and some are for a limited duration, which BGE anticipates being able to extend or replace prior to expiration.

BGE s kWh sales and peak electricity load are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating. BGE s highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on January 7, 2014 and was 6,526 MW.

BGE s natural gas sales are generally higher during the winter months when cold temperatures create demand for winter heating. BGE s highest daily natural gas send out occurred on February 5, 2007 and was 840 mmcf.

The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenues from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per

customer on BGE s electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenues per customer, by customer class, regardless of changes in consumption levels. This adjustment allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period (referred to as revenue decoupling). Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits affected customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Retail Electric Services

BGE s retail electric sales and distribution service revenues are derived from electricity deliveries at rates regulated by the MDPSC. As a result of the deregulation of electric generation in Maryland effective July 1, 2000, all customers can choose a competitive electric generation supplier. While BGE does not sell electric supply to all customers in its service territory, BGE continues to deliver electricity to all customers and provides meter reading, billing, emergency response, and regular maintenance services. Customer choice program activity affects revenue collected from customers related to supplied energy; however, that activity has minimal impact on electric revenue net of purchased power expense or BGE s financial position. At December 31, 2013, there were 73 competitive electric generation suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing energy from a competitive electric generation supplier was approximately 399,000, representing 32% of total retail customers. Retail deliveries purchased from competitive electric generation suppliers represented approximately 61% of BGE s retail kWh sales for the year ended December 31, 2013.

BGE is obligated to provide market-based SOS to all of its electric customers. The SOS rates charged recover BGE s wholesale power supply costs and include an administrative fee. The administrative fee includes a commercial and industrial shareholder return component and an incremental cost component. Bidding to supply BGE s market-based SOS occurs through a competitive bidding process approved by the MDPSC. Successful bidders, which may include Generation, will execute contracts with BGE for terms of three months or two years.

BGE is obligated by the MDPSC to provide several variations of SOS to commercial and industrial customers depending on customer load.

Electric Distribution Rate Cases. In December 2010, the MDPSC issued an abbreviated electric rate order authorizing BGE to increase electric distribution rates for service rendered on or after December 4, 2010 by no more than $31 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010. As part of the March 2011 comprehensive rate order, BGE was authorized to defer $19 million of costs as regulatory assets. These costs are being recovered over a 5-year period beginning in December 2010 and include the deferral of $16 million of storm costs incurred in February 2010. The regulatory asset for the storm costs earns the authorized rate of return.

On July 27, 2012, BGE filed an application for an increase to its electric base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 electric rate case for increases in annual distribution service revenue of $81 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%.

On May 17, 2013, BGE filed an application for an increase to its electric base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE s 2013 electric distribution rate case authorizing an increase in annual distribution service revenue of $34 million. The electric distribution rate increase was set using an allowed return on equity of 9.75%. The approved electric distribution rate became effective for services rendered on or after December 13, 2013.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In August 2010, the MDPSC approved BGE s $480 million SGIP, which includes deployment of a two-way communications network, 2 million smart electric and gas meters and modules, new customer pricing programs, a new customer web portal and numerous enhancements to BGE operations. Also, in April 2010, BGE entered into a Financial Assistance Agreement with the DOE for SGIG funds under the ARRA of 2009. Under the SGIG, BGE has been awarded $200 million, the maximum grant allowable under the program, to support its Smart Grid, Peak Rewards and CC&B initiatives. The SGIG funding is being used to reduce significantly the rate impact of those investments on BGE customers. As of December 31, 2013, BGE has billed the entire $200 million grant to the DOE.

Energy Efficiency Programs. BGE s energy efficiency programs include a CFL program, retrofit programs, an energy efficient appliance rebate and trade-in program, rebates and energy efficiency programs for non-profit, educational, governmental and business customers, customer incentives for energy management programs and incentives to help customers reduce energy demand during peak periods. The MDPSC initially approved a full portfolio of conservation programs as well as a customer surcharge to recover the associated costs. This customer surcharge is updated annually. In December 2011, the MDPSC approved BGE s conservation programs for implementation in 2012 through 2014.

Natural Gas

BGE s natural gas sales are derived pursuant to a MBR mechanism that applies to customers who buy their gas from BGE. Under this mechanism, BGE s actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE s actual cost and the market index is shared equally between shareholders and customers. Customer choice program activity affects revenue collected from customers related to supplied natural gas; however, that activity has minimum impact on gas revenue net of purchased power expense or BGE s financial position. At December 31, 2013, there were 41 competitive natural gas suppliers serving BGE customers. At December 31, 2013, the number of retail customers purchasing fuel from a competitive natural gas supplier was approximately 172,000 representing 26% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 54% of BGE s retail mmcf sales for the year ended December 31, 2013.

BGE must secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed price contracts are recovered under the MBR mechanism and are not subject to sharing. BGE meets its natural gas load requirements through firm pipeline transportation and storage entitlements. BGE s current pipeline firm transportation entitlements to serve its firm loads are 362 mmcf per day.

BGE s current maximum storage entitlements are 284 mmcf per day. To supplement its gas supply at times of heavy winter demands and to be available in temporary emergencies affecting gas supply, BGE has:

- a liquefied natural gas facility for the liquefaction and storage of natural gas with a total storage capacity of 1,055 mmcf and a daily capacity of 332 mmcf,
- a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 6 mmcf and a daily capacity of 6 mmcf, and
- a propane air facility and a mined cavern with a total storage capacity equivalent to 561 mmcf and a daily capacity of 85 mmcf.

BGE has under contract sufficient volumes of propane for the operation of the propane air facility and is capable of liquefying sufficient volumes of natural gas during the summer months for operations of its liquefied natural gas facility during peak winter periods. BGE historically has been able to arrange short-term contracts or exchange agreements with other gas companies in the event of short-term disruptions to gas supplies or to meet additional demand.

BGE also participates 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 shareholders and customers. BGE makes these sales as part of a program to balance its supply of, and cost of, natural gas.

Natural Gas Distribution Rate Cases. In December 2010, the MDPSC issued a rate order authorizing BGE to increase the gas distribution base revenue requirement for service rendered on or after December 4, 2010 by no more than $9.8 million. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated combined electric and gas distribution rate order issued in December 2010.

On July 27, 2012, BGE filed an application for an increase to its gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 gas rate case for increases in annual distribution service revenue of $32 million. The electric distribution rate increase was set using an allowed return on equity of 9.60%.

On May 17, 2013, BGE filed an application for an increase to its gas base rates with the MDPSC. On December 13, 2013, the MDPSC issued an order in BGE s 2013 natural gas distribution rate case authorizing an increase in annual distribution service revenue of $12 million. The gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved natural gas distribution rate became effective for services rendered on or after December 13, 2013.

Construction Budget

BGE s business is capital intensive and requires significant investments primarily in electric and natural gas distribution and electric transmission facilities to ensure the adequate capacity, reliability and efficiency of its system. BGE, as a transmission facilities owner, has various construction commitments under PJM s RTEP as discussed in Note 3 of the Combined Notes to Consolidated Financial Statements. BGE s most recent estimate of capital expenditures for plant additions and improvements for 2014 is approximately $600 million, which includes capital expenditures related to the SGIP net of expected SGIG DOE reimbursements.

ComEd, PECO and BGE

Transmission Services

ComEd, PECO and BGE provide unbundled transmission service under rates approved by FERC. FERC has used its regulation of transmission to encourage competition for wholesale generation services and the development of regional structures to facilitate regional wholesale markets. Under FERC s open access transmission policy promulgated in Order No. 888, ComEd, PECO and BGE, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost-based rates. ComEd, PECO and BGE are required to comply with FERC s Standards of Conduct regulation governing the communication of non-public information between the transmission owner s employees and wholesale merchant employees.

PJM is the ISO and the FERC-approved RTO for the Mid-Atlantic and Midwest regions. PJM is the transmission provider under, and the administrator of, the PJM Open Access Transmission Tariff (PJM Tariff), operates the PJM energy, capacity and other markets, and, through central dispatch, controls the day-to-day operations of the bulk power system for the PJM region. ComEd, PECO and BGE are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO, BGE and the other transmission owners in PJM have turned over control of their transmission facilities to PJM, and their transmission systems are currently 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 members 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. FERC s order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

PECO default service customers are charged for retail transmission services through a rider designed to recover PECO s PJM transmission network service charges and RTEP charges on a full and current basis in accordance with the 2010 electric distribution rate case settlement.

The transmission rate in the PJM Open Access Transmission Tariff under which PECO incurs costs to serve its default service customers and earns revenue as a transmission facility owner is a FERC-approved rate. This is the rate that all load serving entities in the PECO transmission zone pay for wholesale transmission service.

BGE s transmission rates are established based on a formula that was approved by FERC in April 2006. FERC s order establishes the agreed-upon treatment of costs and revenues in the determination of network service transmission rates and the process for updating the formula rate calculation on an annual basis.

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Employees

As of December 31, 2013, Exelon and its subsidiaries had 25,829 employees in the following companies, of which 8,602 or 33% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 (a)	IBEW Local 614 (b)	Other CBAs (c)	Total Employees Covered by CBAs	Total Employees
Generation	1,690	100	1,973	3,763	11,973
ComEd	3,487			3,487	5,895
PECO		1,254		1,254	2,418
BGE					3,303
Other (d)	71		27	98	2,240
Total	5,248	1,354	2,000	8,602	25,829

(a)

A separate CBA between ComEd and IBEW Local 15, ratified on October 10, 2012, covers approximately 32 employees in ComEd s System Services Group. Generation s and ComEd s separate CBAs with IBEW Local 15 were extended through February 28, 2014.

(b) 1,254 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire on March 31, 2015. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires on November 3, 2016 and covers 107 employees.

(c) During 2013, Generation finalized a CBA with the Security Officer union at Oyster Creek, which will expire in 2016. Additionally, during 2013, three other 3-year agreements were negotiated: Power, IBEW Local 614, which will expire in 2016; New England ENEH, UWUA Local 369, which will expire in 2017; and New Energy IUOE Local 95-95A, which will expire in 2016. During 2012, Generation finalized CBAs with the Security Officer unions at Byron, Clinton and TMI, which expire between 2015 and 2016. During 2011, Generation finalized CBAs with the Security Officer unions at Braidwood, Dresden, LaSalle and Quad Cities, which expire between 2014 and 2015. During 2010, Generation entered into a CBA with the Security Officer union at Limerick, which expires in 2014. Additionally, during 2009, a 5-year agreement was reached with Oyster Creek Nuclear Local 1289, which expires in 2015.

(d) Other includes shared services employees at BSC.

Environmental Regulation

General

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

The Exelon board of directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental compliance and strategy, including the CEO; the Senior Vice President, Corporate Strategy and Chief Sustainability Officer; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd, PECO and BGE. 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 has delegated to its corporate governance committee authority to oversee Exelon s compliance with laws and regulations and its strategies and efforts to protect and improve the quality of the environment, including, Exelon s climate change and sustainability policies and programs, and Exelon 2020, Exelon s comprehensive business and environmental plan, as discussed in further detail below. The Exelon board has also delegated to its generation oversight committee authority to oversee environmental, health and safety issues relating to Generation. The respective boards of ComEd, PECO and BGE, which each include directors who also serve on the Exelon board, oversee environmental, health and safety issues related to ComEd, PECO and BGE.

Air Quality

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

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR and CAIR, the regulation of hazardous air pollutants from coal- and oil-fired electric generating facilities under MATS, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

Water Quality

Under the Clean Water Act, NPDES permits for discharges into waterways are required to be obtained from the U.S. EPA or from the state environmental agency to which the permit program has been delegated and must be renewed periodically. Certain of Generation s power generation facilities discharge industrial wastewater into waterways and are therefore subject to these regulations and operate under NPDES permits or pending applications for renewals of such permits after being granted an administrative extension.

See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the impact to Exelon of state permitting agencies administration of the Phase II rule implementing Section 316(b) of the Clean Water Act.

Generation is also subject to the jurisdiction of certain other state and regional agencies and compacts, including the Delaware River Basin Commission and the Susquehanna River Basin Commission.

Solid and Hazardous Waste

The CERCLA provides for immediate response and removal actions coordinated by the U.S. EPA in the event of threatened releases of hazardous substances into the environment and authorizes the U.S. 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 U.S. EPA on the National Priorities List (NPL). These PRPs can be ordered to perform a cleanup, can be sued for costs associated with a U.S. EPA-directed cleanup, may voluntarily settle with the U.S. 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 Illinois, Maryland and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd, PECO and BGE and their subsidiaries are, or are likely to become, parties to proceedings initiated by the U.S. 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 of the Combined Notes to Consolidated Financial Statements for additional information regarding solid and hazardous waste regulation and legislation.

Environmental Remediation

ComEd s, PECO s and BGE s environmental liabilities primarily arise from contamination at former MGP sites. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, have an on-going process to recover environmental remediation costs of the MGP sites through a provision within customer rates. While BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs on a site-specific basis in distribution rates. The amount to be expended in 2014 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $40 million, consisting of $33 million, $6 million and $1 million at ComEd, PECO and BGE, respectively.

Generation s environmental liabilities primarily arise from contamination at current and former generation and waste storage facilities. As of December 31, 2013, Generation has established an appropriate liability to comply with environmental remediation requirements including contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue, and at a disposal facility named West Lake Landfill, both near St. Louis, Missouri related to operations conducted by Cotter Corporation, a former ComEd subsidiary.

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

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants environmental remediation efforts and related impacts to the Registrants results of operations, cash flows and financial position.

Global Climate Change

Exelon believes the evidence of global climate change is compelling and that the energy industry, though not alone, is a significant contributor to the human-caused emissions of GHGs that many in the scientific community believe contribute to global climate change, and as reported by the Intergovernmental Panel on Climate Change in their Fifth Assessment Report Summary for Policy Makers issues September 2013. Exelon, as a producer of electricity from predominantly low-carbon generating facilities (such as nuclear, hydroelectric, wind and solar photovoltaic), has a relatively small GHG emission profile, or carbon footprint, compared to other domestic generators of electricity. By virtue of its significant investment in low-carbon intensity assets, Generation s emission intensity, or rate of carbon dioxide equivalent (CO_2e) emitted per unit of electricity generated, is among the lowest in the industry. Exelon does produce GHG emissions, primarily at its fossil fuel-fired generating plants; CO_2, methane and nitrous oxide are all emitted in this process, with CO_2 representing the largest portion of these GHG emissions. GHG emissions from combustion of fossil fuels represent the majority of Exelon s direct GHG emissions in 2013, although only a small portion of Exelon s electric supply is from fossil generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the natural gas systems, sulfur hexafluoride (SF_6) leakage in its electric transmission and distribution operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity at its facilities. Despite its focus on low-carbon generation, Exelon believes its operations could be significantly affected by the possible physical risks of climate change and by mandatory programs to reduce GHG emissions. See ITEM 1A. RISK FACTORS for information regarding the market and financial, regulatory and legislative, and operational risks associated with climate change.

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

International Climate Change Regulation. At the international level, the United States has not yet ratified the United Nations Kyoto Protocol, which was extended at the 2012 meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18). The Kyoto Protocol now requires participating developed countries to cap GHG emissions at certain levels until 2020, when the new global agreement on emissions reduction is scheduled to become effective. This new global agreement for GHG emissions reductions was agreed to only in concept during the COP18, with a timeline for establishing the global targets by 2015. On November 22, 2013, at the 2013 COP 19 held in Warsaw, Poland, participating countries further agreed to provide their intended nationally determined contributions by the first quarter of 2015 in preparation for formally setting global target in 2015. The other major issues discussed at COP 19 were demands from developing countries for increased climate finance, and for a new mechanism to help especially vulnerable nations cope with unavoidable loss and damage resulting from climate change. Developed countries, which had previously promised to mobilize a total of $100 billion a year by 2020, refused to set a quantified interim goal for ramping up climate finance.

Federal Climate Change Legislation and Regulation. Various stakeholders, including Exelon, legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors are considering ways to address the climate change issue, including the enactment of federal climate change legislation. It is highly uncertain whether Federal legislation to reduce GHG emissions will be enacted. If such legislation is adopted, Exelon may incur costs either to further limit or offset the GHG emissions from its operations or to procure emission allowances or credits. In June 2013, the White House released the President s Climate Action Plan which consists of a wide variety of executive actions targeting GHG reductions, preparing for the impacts of climate change and showing leadership internationally; but the plan did not directly trigger any new requirements or legislative action.

The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President Obama s June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President s memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources.

Regional and State Climate Change Legislation and Regulation. After a two-year program review, the nine northeast and mid-Atlantic states currently participating in the Regional Greenhouse Gas Reduction Initiative (RGGI) released an updated RGGI Model Rule and Program Review Recommendations Summary on February 7, 2013. Under the updated RGGI program, which must be approved pursuant to the applicable legislative and/or regulatory process in each RGGI state, the regional RGGI CO2 budget would be reduced, starting in 2014, from its current 165 million ton level to 91 million tons, with a 2.5 percent reduction in the cap level each year between 2015-2020. Included in the new program are provisions for cost containment reserve (CCR) allowances, which will become available if the total demand for allowances, above the CCR trigger price, exceeds the number of CO2 allowances available for purchase at auction. (CCR trigger prices are $4 in 2014, $6 in 2015, $8 in 2016 and $10 in 2017, rising 2.5 percent thereafter to account for inflation). Such an outcome could put modest upward pressure on wholesale power prices; however, the specifics are currently uncertain.

At the state level, the Illinois Climate Change Advisory Group, created by Executive Order 2006-11 on October 5, 2006, made its final recommendations on September 6, 2007 to meet the Governor s GHG reduction goals. At this time, the only requirements imposed by the state of Illinois are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

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

The Maryland Commission on Climate Change released its climate action plan on August 27, 2008, recommending that the state begin implementing 42 greenhouse gas reduction strategies. One of the Plan s policy recommendations, to adopt science-based regulatory goals to reduce Maryland s GHG emissions, was realized with the passage of the Greenhouse Gas Emissions Reduction Act of 2009 (GGRA). The law requires Maryland to reduce its GHG emissions by 25 percent below 2006 levels by 2020. It directed the MDE to work with other state agencies to prepare an implementation plan to meet this goal. The implementation plan was published in October of 2013. Maryland targeted electricity consumption reduction goals required under the Empower Maryland program, and mandatory State participation in the recently updated and enhanced RGGI Program are listed as that sector s contribution in the plan. The plan also advocates raising the renewable portfolio standard requirement from 22% by 2022 to 25% by 2022.

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

With the announcement in 2008 of Exelon 2020, Exelon set a voluntary goal to reduce, offset or displace more than 15.7 million metric tonnes of GHG emissions per year by 2020. Exelon updated that goal in 2012 following the Constellation merger to account for the integration of former Constellation GHG goals. The updated Exelon 2020 goal is to reduce, offset or displace more than 17.5 million metric tonnes of GHG emissions by 2020. The Exelon 2020 goal encompasses three broad areas of focus: reducing or offsetting Exelon s own carbon footprint (with the year the asset/operations were acquired by Exelon as the baseline), helping customers and communities reduce their GHG emissions, and offering more low-carbon electricity in the marketplace. Exelon has been maintaining strong performance towards achieving the goal and anticipates reaching the 17.5 million tons of annual abatement well before 2020.

Renewable and Alternative Energy Portfolio Standards

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

The Illinois Settlement Legislation required that procurement plans implemented by electric utilities include cost-effective renewable energy resources or approved equivalents such as RECs in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers by June 1, 2008, increasing to 10% by June 1, 2015, with a goal of 25% by June 1, 2025. Utilities are allowed to pass-through any costs from the procurement of these renewable resources or approved equivalents subject to legislated rate impact criteria. As of December 31, 2013, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act became effective for PECO on January 1, 2011, following the expiration of PECO s transition period. During 2013, PECO was required to supply approximately 4.0% of electric energy generated from Tier I (including solar, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, fuel cells, biomass energy, coal mine methane and black liquor generated within Pennsylvania) through May 31, 2013 and subsequently 4.5% beginning June 1, 2013 and continuing through May 31, 2014. PECO was also required to supply 6.2% of electric energy generated from Tier II (including waste coal, demand-side management, large-scale hydropower, municipal solid waste, generation of electricity utilizing wood and by-products of the pulping process and wood, distributed generation systems and integrated combined coal gasification technology) alternative energy resources, respectively, as measured in AECs. The compliance requirements will incrementally escalate to 8.0% for Tier I and 10.0% for Tier II by 2021. In order to comply with these requirements, PECO entered into agreements with varying terms with accepted bidders, including Generation, to purchase non-solar Tier I, solar Tier 1 and Tier II AECs. PECO also purchases AECs through its DSP Program full requirement contracts.

Section 7-703 of the Public Utilities Article in Maryland sets forth the RPS requirement, which applies to all retail electricity sales in Maryland by electricity suppliers. The RPS requirement requires that suppliers obtain a specified percentage of the electricity it sells from Tier 1 sources (solar, wind, biomass, methane, geothermal, ocean, fuel cell, small hydroelectric, and poultry litter) and Tier 2 sources (hydroelectric, other than pump storage generation, and waste-to-energy). The RPS requirement began in 2006, requiring that suppliers procure 1.0% and 2.5% from Tier 1 and Tier 2 sources, respectively, escalating in 2022 to 22.0% from Tier 1 sources, including at least 2.0% from solar energy, and a phase out of Tier 2 resource options by 2022. In 2013, 8.2% was required from Tier 1 renewable sources, including at least 0.25% derived from solar energy, and 2.5% from Tier 2 renewable sources. The wholesale suppliers that supply power to the state s utilities through the SOS procurement auctions have the obligation, by contract with those utilities, to comply with and provide its proportional share of the RPS requirements.

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

See Note 3 and Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 13, 2014

Exelon

Name	**Age**	**Position**	**Period**
Crane, Christopher M.	55	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon	2008 - Present
		President, Generation	2008 - 2013
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
O Brien, Denis P.	53	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	2012 - Present
		Vice Chairman, ComEd, PECO, BGE	2012 - Present
		Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 - 2012
		President and Director, PECO	2003 - 2012

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Gillis, Ruth Ann M.	59	Executive Vice President, Exelon	2008 - Present
		Chief Administrative Officer, Exelon	2010 - Present
		President, Exelon Business Services Company	2005 - Present
		Chief Diversity Officer, Exelon	2009 - 2012
Von Hoene Jr., William A.	60	Senior Executive Vice President and Chief Strategy Officer, Exelon	2012 - Present
		Executive Vice President, Finance and Legal, Exelon	2009 - 2012
		Executive Vice President and General Counsel, Exelon	2008 - 2009
		Senior Vice President, Exelon Business Services Company	2004 - 2009
Thayer, Jonathan W.	42	Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
Aliabadi, Paymon	51	Executive Vice President and Chief Risk Officer, Exelon	2013 - Present
		Managing Director, Gleam Capital Management	2012 - 2013
		Principal and Managing Director, Gunvor International	2009 - 2011
		Chief Executive Officer, Essent Trading International	2004 - 2009
DesParte, Duane M.	50	Senior Vice President and Corporate Controller, Exelon	2008 - Present

Generation

Name	Age	Position	Period
Cornew, Kenneth W.	48	Senior Executive Vice President and Chief Commercial Officer, Exelon;	2013 - Present
		President and CEO, Generation	2013 - Present
		Executive Vice President and Chief Commercial Officer, Exelon	2012 - 2013
		President and Chief Executive Officer, Constellation	2012 - 2013
		Senior Vice President, Exelon; President, Power Team	2008 - 2012

Name	Age	Position	Period
Pacilio, Michael J.	53	President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - Present
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
Nigro, Joseph	49	Executive Vice President, Exelon; Chief Executive Officer, Constellation	2013 - Present
		Senior Vice President, Portfolio Management and Strategy	2012 - 2013
		Vice President, Structuring and Portfolio Management, Exelon Power Team	2010 - 2012
DeGregorio, Ronald	51	Senior Vice President, Generation; President, Exelon Power	2012 - Present
		Chief Integration Officer, Exelon	2011 - 2012
		Chief Operating Officer, Exelon Transmission Company	2010 - 2011
		Senior Vice President, Mid-Atlantic Operations, Exelon Nuclear	2007 - 2010
Wright, Bryan P.	47	Senior Vice President and Chief Financial Officer, Generation	2013 - Present
		Senior Vice President, Corporate Finance, Exelon	2012 - 2013
		Chief Accounting Officer, Constellation Energy	2009 - 2012
		Vice President and Controller, Constellation Energy	2008 - 2012
Aiken, Robert	47	Vice President and Controller, Generation	2012 - Present
		Executive Director and Assistant Controller, Constellation	2011 - 2012
		Executive Director of Operational Accounting, Constellation Energy Commodities Group	2009 - 2011
		Vice President of International Accounting, Constellation Energy Commodities Group	2007 - 2009

ComEd

Name	Age	Position	Period
Pramaggiore, Anne R.	55	Chief Executive Officer, ComEd	2012 - Present
		President, ComEd	2009 - Present
		Chief Operating Officer, ComEd	2009 - 2012
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 - 2009
Donnelly, Terence R.	53	Executive Vice President and Chief Operating Officer, ComEd	2012 - Present
		Executive Vice President, Operations, ComEd	2009 - 2012
		Senior Vice President, Transmission and Distribution, ComEd	2007 - 2009
Trpik Jr., Joseph R.	44	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 - Present
		Vice President & Assistant Corporate Controller, Exelon Business Services Company	2007 - 2009
		Vice President and Assistant Corporate Controller, Exelon	2004 - 2009

Name	Age	Position	Period
Jensen, Val	58	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
O Neill, Thomas S.	51	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 - Present
		Senior Vice President, Exelon	2009 - 2010
		Senior Vice President, New Business Development, Generation; Senior Vice President, New Business Development, Exelon	2009 - 2009
		Vice President, New Plant Development, Generation	2007 - 2009
Marquez Jr., Fidel	52	Senior Vice President, Governmental and External Affairs, Exelon	2012 - Present
		Senior Vice President, Customer Operations, ComEd	2009 - 2012
		Vice President of External Affairs and Large Customer Services, ComEd	2007 - 2009
Brookins, Kevin B.	52	Senior Vice President, Strategy & Administration, ComEd	2012 - Present
		Vice President, Operational Strategy and Business Intelligence, ComEd	2010 - 2012
		Vice President, Distribution System Operations, ComEd	2008 - 2010
Anthony, J. Tyler	49	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Kozel, Gerald J.	41	Vice President, Controller, ComEd	2013 - Present
		Assistant Corporate Controller, Exelon	2012 - 2013
		Director of Financial Reporting and Analysis, Exelon	2009 - 2012
		Manager of Accounting, ComEd	2008 - 2009

PECO

Name	Age	Position	Period
Adams, Craig L.	61	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	50	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	48	Senior Vice President and Chief Operations Officer, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010

Name	Age	Position	Period
Webster Jr., Richard G.	52	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	54	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Jiruska, Frank J.	53	Vice President, Customer Operations, PECO	2013 - Present
Diaz Jr., Romulo L.	67	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
		Associate General Counsel, Exelon	2008 - 2009
Bailey, Scott A.	37	Vice President and Controller, PECO	2012 - Present
		Assistant Controller, Generation	2011 - 2012
		Director of Accounting, Power Team	2007 - 2011

BGE

Name	Age	Position	Period
DeFontes Jr., Kenneth W.	63	President and Chief Executive Officer, BGE	2004 - Present(a)
		Senior Vice President, Constellation Energy	2004 - 2012
Woerner, Stephen J.	46	Chief Operating Officer, BGE	2012 - Present
		Senior Vice President, BGE	2009 - Present
		Vice President and Chief Integration Officer, Constellation Energy	2011 - 2012
		Vice President and Chief Information Officer, Constellation Energy	2010 - 2011
		Vice President, Transformation, Constellation Energy	2009 - 2010
		Senior Vice President, Gas and Electric Operations and Planning, BGE	2007 - 2009
Khouzami, Carim V.	38	Senior Vice President, Chief Financial Officer and Treasurer, BGE	2013 - Present
		Vice President, Chief Financial Officer and Treasurer, BGE	2011 - 2013
		Executive Director, Investor Relations, Constellation Energy	2009 - 2011
		Director, Corporate Strategy and Development, Constellation Energy	2008 - 2009
Butler, Calvin	44	Senior Vice President, Regulatory and External Affairs, BGE	2013 - Present(a)
		Senior Vice President, Corporate Affairs, Exelon	2011 - 2013
		Senior Vice President, Human Resources, Exelon	2010 - 2011
		Senior Vice President, Corporate Affairs, ComEd	2009 - 2010

Name	Age	Position	Period
Case, Mark D.	52	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Dodson, Carol A.	49	Vice President, Customer Operations, BGE	2013 - Present
		Chief Customer Officer, BGE	2013 - Present
		Vice President, Utility Oversight, BSC	2012 - 2013
		Vice President, Engineering and Project Management, BGE	2012 - 2012
		Senior Vice President, Asset Management Services, BGE	2009 - 2012
Gahagan, Daniel P.	60	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	41	Vice President and Controller, BGE	2012 - Present
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010

(a) On February 12, 2014, Kenneth W. DeFontes Jr., President and Chief Executive Officer at BGE announced his retirement from BGE on February 28, 2014. Effective March 1, 2014, Calvin G. Butler Jr. will become Chief Executive Officer of BGE and an executive officer of Exelon and Stephen J. Woerner will become President and continue as Chief Operating Officer of BGE.

ITEM 1A. RISK FACTORS

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

The Registrants most significant risks arise as a consequence of: (1) Generation s position as a predominantly nuclear generator selling power into competitive energy markets with a concentration in select regions, and (2) the role of ComEd, PECO and BGE as operators of electric transmission and distribution systems in three of the largest metropolitan areas in the United States. The Registrants major risks fall primarily under the following categories:

Market and Financial Risks. Exelon s and Generation s market and financial risks include the risk of price fluctuations in the power 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 prices of natural gas and coal, which drive the prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation s output is sold, (3) the effects on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Regulatory and Legislative Risks. The Registrants regulatory and legislative risks include changes to the laws and regulations that govern competitive markets and utility cost recovery, and that drive environmental policy. In particular, Exelon s and Generation s financial performance may be adversely affected by changes that could affect Generation s ability to sell power into the competitive wholesale power markets at market-based prices. In addition, potential regulation and legislation regarding climate change and renewable portfolio standards could increase the pace of development of wind energy facilities, which could put downward pressure in some markets on wholesale market prices for electricity from Generation s nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation s nuclear assets under a carbon constrained regulatory regime that might exist in the future. Also, regulatory actions in Illinois, Pennsylvania or Maryland could materially lower returns for ComEd, PECO and BGE, respectively.

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

Risks Related to the Merger with Constellation and the Pending Master Agreement between Generation and CENG. As a result of the merger with Constellation that closed on March 12, 2012, Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals from the July 29, 2013 Master Agreement between Exelon, Generation and subsidiaries of Generation with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG. Exelon and Generation are subject to the risks that integration of CENG s nuclear fleet may not achieve anticipated results, and that Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

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

Market and Financial Risks

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

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

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

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

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 an environment 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 can adversely affect overall gross margins and profitability in Generation s retail operations.

Sustained low market prices or depressed demand and over-supply could adversely affect Exelon s and Generation s results of operations and cash flows, and such impacts could be emphasized given Generation s concentration of base-load electric generating capacity within primarily two geographic market regions, namely the Midwest and the Mid-Atlantic. These impacts could adversely affect Exelon s and Generation s ability to fund other discretionary uses of cash such as growth projects or to pay dividends. In addition, such conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Exelon s and Generation s results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs which may be offset in whole or in part by reduced operating and maintenance expenses. A slow recovery in market conditions could result in a prolonged depression of or further decline in commodity prices, including low forward natural gas and power prices and low market volatility, which could also adversely affect Exelon s and Generation s results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the power markets that are beyond its control and may 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 might 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 may 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.

Unstable Markets. The wholesale spot markets remain evolving markets that vary from region to region and are still developing practices and procedures. Problems in or the 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 exposed to emerging technologies that may over time affect or transform the energy industry, including technologies related to energy generation, distribution and consumption. (Exelon, Generation, ComEd, PECO and BGE)

Some of these technologies include, but are not limited to further shale gas development or sources, cost-effective renewable energy technologies, broad consumer adoption of electric vehicles and energy storage devices. Such developments could lower the price of energy, could affect energy deliveries as customer-owned generation becomes more cost-effective, could require further improvements to our distribution systems to address changing load demands and could make portions of our electric system power supply and transmission and/or distribution facilities obsolete prior to the end of their useful lives. Such technologies could also result in further declines in commodity prices or demand for delivered energy. Each of these factors could materially affect the Registrants results of operations, financial position, and cash flows 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 may decrease the value of NDT funds and employee benefit plan assets and increase the related employee benefit plan obligations, which then could require significant additional funding. (Exelon, Generation, ComEd, PECO and BGE)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may 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 may fall below the Registrants projected return rates. A decline in the market value of the NDT fund investments may increase Generation s funding requirements to decommission its nuclear plants. A decline in the market value of the pension and other postretirement benefit plan assets will increase the funding requirements associated with Exelon s pension and other postretirement benefit plan obligations. Additionally, Exelon s pension and other postretirement benefit 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 may also increase the costs and funding requirements of the obligations related to the pension and other postretirement benefit 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 ComEd, PECO and BGE customers, the results of operations and financial positions of ComEd, PECO and BGE could be negatively affected. Ultimately, if the Registrants are unable to manage the investments with the NDT funds and benefit plan assets, and unable to manage the related benefit plan liabilities, their results of operations, cash flows and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may 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 adversely affect the Registrants financial condition, results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

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 can 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 is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. The inability to access capital markets or credit facilities, and longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation s hedging strategy in order to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. Disruptions in the European markets could reduce or restrict the Registrants ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2013, approximately 30%, or $2.5 billion, of the Registrants available credit facilities were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants credit facilities as of December 31, 2013. See Note 13 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

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

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 trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd, PECO and BGE)

Generation s business is subject to credit quality standards that may 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 may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent 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.

ComEd s operating agreement with PJM contains collateral provisions that are affected by its credit rating and market prices. If certain wholesale market conditions exist and ComEd were to lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required under the PJM operating agreement to provide collateral in the forms of letters of credit or cash, which may have a material adverse effect upon its liquidity. Collateral posting will generally increase as market prices rise and decrease as market prices fall. Given the relationship to forward market prices, contract collateral requirements can be volatile. In addition, if ComEd were downgraded, it could experience higher borrowing costs as a result of the downgrade.

PECO s and BGE s operating agreements with PJM and their natural gas procurement contracts contain collateral provisions that are affected by their credit ratings. If certain wholesale market conditions exist and PECO and BGE were to lose their investment grade credit ratings (based on their senior unsecured debt ratings), they would be required to provide collateral in the form of letters of credit or cash, which may have material adverse effects upon their liquidity. PECO s and BGE s collateral requirements relating to their natural gas supply contracts are a function of market prices. Collateral posting requirements for PECO and BGE with respect to these 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 PECO or BGE were downgraded, they could experience higher borrowing costs as a result of the downgrade.

ComEd, PECO or BGE 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 ComEd, PECO, or BGE in particular, has deteriorated. ComEd, PECO or BGE could experience a downgrade if the current regulatory environments in Illinois, Pennsylvania or Maryland, respectively, become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd, PECO or BGE could be downgraded if their financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage their capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd, PECO or BGE.

ComEd, PECO and BGE conduct their respective businesses and operate under governance models and other arrangements and procedures intended to assure that ComEd, PECO and BGE are treated as separate, independent companies, distinct from Exelon and other Exelon subsidiaries in order to isolate ComEd, PECO and BGE from Exelon and other Exelon subsidiaries in the event of financial difficulty at Exelon or another Exelon subsidiary. These measures (commonly referred to as ringfencing) may help avoid or limit a downgrade in the credit ratings of ComEd, PECO and BGE in the event of a reduction in the credit rating of Exelon. Despite these ringfencing measures, the credit ratings of ComEd, PECO or BGE 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 ComEd, PECO or BGE, or all three. A reduction in the credit rating of ComEd, PECO or BGE could have a material adverse effect on ComEd, PECO or BGE, respectively.

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

Generation s financial performance may 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 its generating facilities. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. Coal, natural gas and oil are procured for generating plants through annual, short-term and spot-market purchases. The supply markets for nuclear fuel, coal, natural gas and oil are subject to price fluctuations, availability restrictions and counterparty default that may negatively affect the results of operations for Generation.

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

Generation s asset-based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may 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 may have on its business, operating results, cash flows or financial position.

Generation buys and sells energy and other products in the wholesale markets and enters into financial contracts to manage risk and hedge various positions in Generation s power generation portfolio. The proportion of hedged positions in its power generation portfolio may cause volatility in Generation s future results of operations.

Financial performance and load requirements may 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 ComEd, PECO, BGE and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation s wholesale 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 may be negatively affected if it is unable to cost-effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

Challenges to tax positions taken by the Registrants as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could negatively impact the Registrants results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

Corporate Tax Reform. There exists the potential for comprehensive tax reform in the United States that may significantly change the tax rules applicable to U.S. domiciled corporations. Exelon cannot assess what the overall effect of such potential legislation would be on its results of operations and cash flows.

1999 sale of fossil generating assets. The IRS has challenged Exelon s 1999 tax position on its like-kind exchange transaction. Exelon and the IRS failed to reach a settlement on the like-kind exchange position and Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the like-kind exchange position. The litigation could take three to five years including appeals, if necessary.

As of December 31, 2013, if the IRS is successful in its challenge to the like-kind exchange position, Exelon s potential cash outflow, including tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $840 million, of which approximately $305 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless. In addition to attempting to impose tax on the like-kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after-tax charge of $87 million to Exelon s and ComEd s results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like-kind exchange matter are unknown. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1 and 14 of the Combined Notes to Consolidated Financial Statements for additional information.

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

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

Further, the impacts of economic downturns on ComEd, PECO and BGE customers and purchased natural gas costs for PECO and BGE 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, may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd s, PECO s and BGE s results from operations and cash flows. Generation s customer supply activities face economic downturn risks similar to Exelon s utility businesses, such as lower volumes sold and increased expense for uncollectible customer balances. As Generation increases its customer supply footprint, economic downturn impacts could negatively affect Generation s results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants credit risk.

The effects of weather may impact the Registrants results of operations and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

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. Weather conditions directly influence the demand for electricity and natural gas and affect the price of energy commodities. Moderate temperatures adversely affect the usage of energy and resulting revenues at ComEd and PECO. Due to revenue decoupling, BGE recognizes revenues at MDPSC-approved levels per customer, regardless of what actual distribution volumes are for a billing period, and is not affected by actual weather with the exception of major storms. Extreme weather conditions or damage resulting from storms may stress ComEd s, PECO s and BGE s 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 may have detrimental effects on ComEd s, PECO s and BGE s results of operations and cash flows. First and third quarter financial results, in particular, are substantially dependent on weather conditions, and may 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 may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may 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 can impact Generation s ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may 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 may become impaired, which would result in write-offs of the impaired amounts. (Exelon, Generation, ComEd, PECO and BGE)

Long-lived assets represent the single largest asset class on the Registrants statement of financial position. Specifically, long-lived assets account for 59%, 49%, 61%, 66% and 75% of total assets for Exelon, Generation, ComEd, PECO and BGE, respectively, as of December 31, 2013. In addition, the Registrants have significant balances related to unamortized energy contracts. See Notes 4 and 10 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon s unamortized energy contracts. The Registrants evaluate the recoverability of the carrying value of long-lived assets to be held and used whenever events or circumstances indicating a potential impairment exist. Factors such as the business climate, including current and future energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long-lived assets for potential impairment. An impairment would require the Registrants to reduce the carrying value of the long-lived asset through a non-cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants results of operations.

Exelon and Generation have investments in certain generating plant projects, including the CENG nuclear joint venture with a carrying value of $1.9 billion as of December 31, 2013. These investments were acquired in the March 2012 Constellation transaction, and were recorded as equity method investments on the balance sheet at fair value on the merger date as part of purchase accounting. Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such issues indicate an other than temporary decline in value. Such impairment could have a material adverse impact on Exelon s and Generation s results of operations.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records a non-cash impairment charge to expense if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Such an impairment could have a material adverse impact on Exelon s results of operations.

Exelon and ComEd had approximately $2.6 billion of goodwill recorded at December 31, 2013 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. 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, reducing equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A successful IRS challenge to Exelon s and ComEd s like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in significant assumptions used in estimating ComEd s fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non-cash charge to expense, which could have a material adverse impact on Exelon s and ComEd s results of operations.

See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Critical Accounting Policies and Estimates and Notes 7, 8 and 10 of the Combined Notes to the Consolidated Financial Statements for additional discussion on long-lived asset and goodwill impairments.

The Registrants businesses are capital intensive, and their assets may require significant expenditures to maintain and are subject to operational failure, which could result in potential liability. (Exelon, Generation, ComEd, PECO and BGE)

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

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non-performance by third parties. In addition, the Registrants have rights under agreements which obligate third parties to indemnify the Registrants for various obligations, and the Registrants may 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. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have issued guarantees of the performance of third parties, which obligate one or more of the Registrants or their subsidiaries to perform in the event that the third parties do not perform. In the event of non-performance by those third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants.

The Registrants have entered into various agreements with counterparties that require those counterparties to reimburse a Registrant and hold it harmless against specified obligations and claims. To the extent that any of these counterparties are affected by deterioration in their creditworthiness or the agreements are otherwise determined to be unenforceable, the affected Registrant could be held responsible for the obligations, which could impact that Registrant s results of operations, cash flows and financial position. In connection with Exelon s 2001 corporate restructuring, Generation assumed certain of ComEd s and PECO s rights and obligations with respect to their former generation businesses. Further, ComEd and PECO may have entered into agreements with third parties under which the third-party agreed to indemnify ComEd or PECO for certain obligations related to their respective former generation businesses that have been assumed by Generation as part of the restructuring. If the third-party or Generation experienced events that reduced its creditworthiness or the indemnity arrangement became unenforceable, ComEd or PECO could be liable for any existing or future claims, which could impact ComEd s or PECO s results of operations, cash flows and financial position.

Generation s business may be negatively affected by competitive electric generation suppliers. (Exelon and Generation)

Because retail customers where Generation serves load can switch from their respective energy delivery company to a competitive electric generation supplier for their energy needs, planning to meet Generation s obligation to provide the supply needed to serve Generation s share of an electric distribution company s default service obligation is more difficult than planning for retail load before the advent of retail competition. Before retail competition, the primary variables affecting projections of load were weather and the economy. With retail competition, another major factor is retail customers switching to or from competitive electric generation suppliers. If fewer of such customers switch from its retail load serving counterparties than Generation anticipates, the load that Generation must serve will be greater than anticipated, which could, if market prices have increased, increase Generation s costs (due to its need to go to market to cover its incremental supply obligation) more than the increase in Generation s revenues. If more customers from its retail load serving counterparties switch than Generation anticipates, the load that Generation must serve will be lower than anticipated, which could, if market prices have decreased, cause Generation to lose opportunities in the market.

Regulatory and Legislative Risks

The Registrants generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. 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 and financial results. (Exelon, Generation, ComEd, PECO and BGE)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon s and Generation s operating results and

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cash flows are heavily dependent upon the ability of Generation to sell power at market-based rates, as opposed to cost-based or other similarly regulated rates, and Exelon s, ComEd s, PECO s and BGE s operating results and cash flows are heavily dependent on the ability of ComEd, PECO and BGE to recover their costs for the retail purchase and distribution of power to their customers. Similarly, there is risk that financial market regulations could increase the Registrants compliance costs and limit their ability to engage in certain transactions. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, exchanges, ratemaking agencies and taxing authorities. Additionally, the Registrants need to be cognizant of rules 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 adversely affect their results of operations, cash flows and financial position.

Regulatory and legislative developments related to climate change and RPS may also significantly affect Exelon s and Generation s results of operations, cash flows and financial positions. Various legislative and regulatory proposals to address climate change through GHG emission reductions, if enacted, could result in increased costs to entities that generate electricity through carbon-emitting fossil fuels, which could increase the market price at which all generators in a region, including Generation, may sell their output, thereby increasing the revenue Generation could realize from its low-carbon nuclear assets. However, national regulation or legislation addressing climate change through an RPS could also increase the pace of development of wind energy facilities in the Midwest, which could put downward pressure on wholesale market prices for electricity from Generation s Midwest nuclear assets, partially offsetting any additional value Exelon and Generation might derive from Generation s nuclear assets under a carbon constrained regulatory regime that might exist in the future. Current state level climate change and renewable regulation is already providing incentives for regional wind development. The Registrants cannot predict when or whether any of these various legislative and regulatory proposals may become law or what their effect will be on the Registrants.

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

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

Approximately 60% of Generation s generating resources, which include directly owned assets and capacity obtained through long-term contracts, are located in the area encompassed by PJM. Generation s future results of operations will depend on 1) FERC s continued adherence to and support for, policies that favor the preservation of competitive wholesale power markets, such as PJM s, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect market competitiveness. Generation could also be adversely affected by state laws, regulations or initiatives designed to reduce wholesale prices artificially below competitive levels or to subsidize new generation, such as the subsequently dismissed New Jersey Capacity Legislation and the MDPSC s RFP for new gas-fired generation in Maryland. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation and the Maryland new electric generation requirements.

In addition, FERC s application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC s tests for market-based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation s authority to sell at market-based rates and none denying that authority. On December 31, 2013, Generation submitted its triennial application seeking reauthorization to sell at market-based rates in the Northeast region (including PJM, ISO-NY and ISONE). Generation s previous submission seeking reauthorization to sell at market-based rates was accepted by FERC on June 22, 2011 for the PJM region.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis that unfolded during 2008. Dodd-Frank ushers in a brand new regulatory regime applicable to the over-the-counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Generation has determined that it will conduct its commercial hedging business as an end user in a manner that does not require registration as a swap dealer or major swap participant.

Notwithstanding the foregoing, Generation will still face additional regulatory obligations under Dodd-Frank, including some reporting requirements, clearing some additional transactions that it would otherwise enter into over-the-counter, and having to adhere to position limits. More fundamentally, however, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swaps market to decrease substantially. Dodd-Frank may require up to $1 billion of additional collateral requirements at Generation, to be met with cash rather than letters of credit in a price stressed environment. Generation continues to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on its results of operations, cash flows or financial position.

Generation s affiliation with ComEd, PECO and BGE, together with the presence of a substantial percentage of Generation s physical asset base within the ComEd, PECO and BGE service territories, could increase Generation s cost of doing business to the extent future complaints or challenges regarding ComEd, PECO and/or BGE 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 ComEd, PECO and BGE 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 ComEd, PECO and BGE 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 may question or challenge costs incurred by ComEd, PECO or BGE, including transactions between Generation, on the one hand, and ComEd, PECO or BGE, on the other hand, regardless of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may 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 may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd, PECO and BGE)

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 can 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 may be subject to additional proceedings in the future.

If application of Section 316(b) of the Clean Water Act, which establishes a national requirement for reducing the adverse impacts to aquatic organisms at existing generating stations, requires the retrofitting of cooling water intake structures at Salem or other Exelon power plants, this development could result in material costs of compliance. Pursuant to discussions with the NJDEP regarding the application of Section 316(b) to Oyster Creek, Generation agreed to permanently cease generation operations at Oyster Creek by December 31, 2019, ten years before the expiration of its operating license in 2029.

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 may 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 may be limited by the financial resources of the transferee. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd s, PECO s and BGE s 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 may introduce time delays in effectuating rate changes. (Exelon, ComEd, PECO and BGE)

ComEd, PECO and BGE 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 ComEd, PECO or BGE 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 can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

In certain instances, ComEd, PECO and BGE may agree to negotiated settlements related to various rate matters, customer initiatives or franchise agreements. These settlements are subject to regulatory approval.

ComEd, PECO and BGE cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania, Maryland 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 ComEd, PECO and BGE will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations 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 ComEd, PECO and BGE, as applicable, to recover their costs and could have a material adverse effect on ComEd s, PECO s and BGE s results of operations, cash flows and financial position. See Note 3 of the Combined Notes to the Consolidated Financial Statements for information regarding rate proceedings.

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

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

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd, PECO and BGE, 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, ComEd, and PECO. 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, ComEd, PECO and BGE. (Exelon, ComEd, PECO and BGE)

As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE 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, ComEd, PECO and BGE 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 extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd, PECO and BGE. At December 31, 2013, the extraordinary gain (loss) could have been as much as $(2.4) billion, $730 million and $ 453 million (before taxes) as a result of the elimination of ComEd s, PECO s and BGE s regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $2.4 billion and $568 million for ComEd and BGE, respectively, related to Exelon s regulatory assets associated with its defined benefit postretirement plans. Exelon also has a regulatory liability of $45 million (before taxes) associated with PECO s defined benefit postretirement plans that would result in an increase in OCI if reversed. The impacts and resolution of the above items could lead to an additional impairment of ComEd s goodwill, which could be significant and at least partially offset the extraordinary gain at ComEd discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd, PECO and BGE to pay dividends under Federal and state law and no longer meeting the regulatory accounting criteria could cause significant volatility in future results of operations. See Notes 1, 3 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd s goodwill, respectively.

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

Various stakeholders, including legislators and regulators, shareholders and non-governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid-Atlantic states implemented a model rule, developed via the RGGI, to regulate CO_2 emissions from fossil-fired generation. RGGI states are working on updated programs to further limit emissions and the EPA has introduced regulation to address greenhouse gases from new fossil plants that could potentially impact existing plants. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. The nature and extent of environmental regulation may also impact the ability of Exelon and its subsidiaries to meet the GHG emission reduction targets of Exelon 2020. For example, more stringent permitting requirements may preclude the construction of lower-carbon nuclear and gas-fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS Global Climate Change and Note 22 of the Combined Notes to Consolidated Financial Statements.

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

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd, PECO and BGE, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. As operators of natural gas distribution systems, PECO and BGE 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 may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC, PAPUC and MDPSC impose certain distribution reliability standards on ComEd, PECO and BGE, respectively. 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.

ComEd, PECO and BGE 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 may require ComEd, PECO and BGE to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM s RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. Following a remand from the U.S. Court of Appeals for the Seventh Circuit, FERC reaffirmed its decision related to allocation of new facilities 500 kV and above. That decision is being appealed to the U.S. Court of Appeals for the Seventh Circuit. This FERC order only applies to facilities included in the PJM RTEP prior to February 1, 2013. For facilities subsequently approved, the costs of new facilities that are double circuit 345 kV or greater than or equal to 500 kV will be allocated 50% across the entire PJM footprint and 50% allocated to identified beneficiaries. Costs for all other facilities will be allocated to all identified beneficiaries. This later decision is subject to rehearing by FERC and possible appeal.

See Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The Registrants cannot predict the outcome of the legal proceedings relating to their business activities. An adverse determination could have a material adverse effect on their results of operations, financial positions and cash flows. (Exelon, Generation, ComEd, PECO and BGE)

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 of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants results of operations.

Generation may 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 may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation s results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC s focus on seismic risk intensified. As part of the NRC Near-Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. Additionally, the Task Force provided recommendations for future regulatory action by the NRC to be taken in the near and longer term. In response, the NRC issued three immediately effective orders (Tier 1) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. The NRC is currently evaluating the remaining Task Force recommendations and has not taken action with respect to the Tier 2 and Tier 3 recommendations. Actions to comply with the Task Force recommendations will result in increased costs and could significantly impact Generation s results of operations or financial position. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview for a more detailed discussion of the Task Force Recommendations.

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 spent nuclear fuel at nuclear power plants for up to 60 years beyond the original and renewed licensed operating life of the plants. In June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. In September 2012, the NRC directed NRC Staff to complete a generic environmental impact statement and to revise the temporary storage rule which is now not expected until October 3, 2014.

Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation s ability to decommission fully its nuclear units. In accordance with the NWPA and Generation s contract with the DOE, Generation pays the DOE ongoing fees per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. On November 19, 2013, the United States Court of Appeals for the District of Columbia Circuit ordered the DOE to submit to Congress a proposal to reduce the current SNF disposal fee to zero, unless and until there is a viable disposal program. Until such time as a new fee structure is in effect, Generation must continue to pay the current SNF disposal fees. Furthermore, under its contract with the DOE, Generation would be required to pay the DOE a one-time SNF storage fee including interest of approximately $1 billion as of December 31, 2013, prior to the first delivery of SNF. Generation currently estimates 2025 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation.

License renewals. Generation cannot assure that economics will support the continued operation of the facilities for all or any portion of any renewed license period. If the NRC does not renew the operating licenses for Generation s nuclear stations 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, impairment charges and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. In addition, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments.

As discussed above, in June 2012, the United States Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

Operational Risks

The Registrants employees, contractors, customers and the general public may be exposed to a risk of injury due to the nature of the energy industry. (Exelon, Generation, ComEd, PECO and BGE)

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near their operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant 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 may adversely affect Exelon s results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd, PECO and BGE)

Generation s fleet of nuclear and fossil-fueled power plants and ComEd s, PECO s and BGE s distribution and transmission infrastructures could be affected by natural disasters, such as seismic activity, more frequent and more 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. Examples of such events include the June 2012 Derecho storm, which interrupted electric service delivery to customers in BGE s service territory, and the October 2012 category 1 hurricane, Hurricane Sandy, which interrupted electric service delivery to customers in PECO s and BGE s service territories and resulted in significant costs to PECO and BGE for restoration efforts.

Other events include the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co., and the 5.8 magnitude earthquake and flooding associated with Hurricane Irene and Tropical Storm Lee that the Mid-Atlantic region of the United States experienced in 2011. These events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. 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 may adversely affect the Registrants operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. 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 of, or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may 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 may result in a decline in energy consumption, which may adversely affect the Registrants results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would 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 its 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 and casualty losses subject to unforeseen occurrences or catastrophic events that may 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 may 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 ComEd, PECO and BGE. 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, can have a significant impact on Generation s results of operations. When refueling outages at wholly and co-owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales.

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

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

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can 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, may 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 on Generation s results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear-fueled energy and significantly affect Generation s results of operations or financial position.

Nuclear insurance. As required by the Price-Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims exceeding the $13.6 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 of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

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

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can 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 has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from ComEd customers or from the previous owners of Clinton, TMI Unit No. 1 and Oyster Creek generating stations, 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 may be negatively affected and Exelon s and Generation s results of operations and financial position could be significantly affected. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation s NDTs are not sufficient to fund the decommissioning of Generation s nuclear plants, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that current and future NRC minimum funding requirements are met. As a result, Generation s cash flows and financial position may be significantly adversely affected. See Note 15 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s financial performance may 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 Conowingo Hydroelectric Project expires August 31, 2014, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2014. 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 may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation s results of operations or financial position. Similar effects may 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.

ComEd s, PECO s and BGE s operating costs, and customers and regulators opinions of ComEd, PECO and BGE, respectively, are affected by their ability to maintain the availability and reliability of their delivery and operational systems. (Exelon, ComEd, PECO and BGE)

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

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd s, PECO s and BGE s 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 can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd s results of operations and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information regarding proceedings related to storm-related outages in ComEd s service territory.

ComEd s, PECO s and BGE s respective ability to deliver electricity, their operating costs and their capital expenditures may be negatively affected by transmission congestion. (Exelon, ComEd, PECO and BGE)

Demand for electricity within ComEd s, PECO s and BGE s 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 ComEd s, PECO s and BGE s 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 ComEd, PECO and BGE to upgrade or expand their respective transmission systems through additional capital expenditures.

Failure to attract and retain an appropriately qualified workforce may negatively impact the Registrants results of operations. (Exelon, Generation, ComEd, PECO and BGE)

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may 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, may arise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

The Registrants are subject to physical and information security risks. (Exelon, Generation, ComEd, PECO and BGE)

The Registrants face physical and information security risks as the owner-operators of generation, transmission and distribution facilities. A security breach of the physical assets or information systems of the Registrants, their competitors, RTOs and ISOs, or regulators could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject the Registrants to financial harm associated with theft or inappropriate release of certain types of information, including sensitive customer data. If a significant breach occurred, the reputation of Exelon and its customer supply activities may be adversely affected, customer confidence in the Registrants or others in the industry may be diminished, or Exelon and its subsidiaries may be subject to legal claims, any of which may contribute to the loss of customers and have a negative impact on the business and/or results of operations. ComEd s, PECO s and BGE s deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. As a requirement of their SGIG grant, the DOE approved PECO s and BGE s cyber security plan related to its smart meter deployment and will review the plan annually through the expiration of the grant. As with most companies in today s environment, Exelon experiences attempts by hackers to infiltrate its corporate network. To date there have been no infiltrations that have resulted in loss of data or any significant effects on business operations. Exelon utilizes a dedicated team of cyber security professionals to ensure the protection of its information and ability to conduct business operations. Despite the measures taken by the Registrants to prevent a security breach, the Registrants cannot accurately assess the probability that a security breach may occur and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations could require changes in current measures taken by the Registrants or their business operations and could adversely affect their results of operations, cash flows and financial position.

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

Generation continuously looks to invest in new business initiatives and actively participate in new markets. These include, but are not limited to, unconventional oil and gas exploration and production, residential power and gas sales, solar and wind generation, and managed load response. Such initiatives may 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 may 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 may 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. ComEd, PECO and BGE face risks associated with the Smart Grid mandated regulatory initiative. These risks include, but are not limited to, cost recovery, regulatory concerns, cyber security and obsolescence of technology. Due to these risks, no assurance can be given that such initiatives will be successful and will not have a material adverse effect on ComEd s, PECO s or BGE s financial results.

Risks Related to the Merger

Exelon may encounter unexpected difficulties or costs in meeting commitments it made under various orders and agreements associated with regulatory approvals for the Constellation merger.

As a result of the process to obtain regulatory approvals required for the Constellation merger, Exelon is committed to various programs, contributions, investments and market mitigation measures in several settlement agreements and regulatory approval orders. It is possible that Exelon may encounter delays, unexpected difficulties or costs in meeting these commitments in compliance with the terms of the relevant agreements and orders. Failure to fulfill the commitments in accordance with their terms could result in increased costs or result in penalties or fines that could adversely affect Exelon s financial position and operating results.

Risks Related to the Pending Master Agreement with CENG

The integration of CENG s nuclear fleet may not achieve its anticipated results, and Exelon and Generation may not be able to fully integrate the operations of CENG in the manner expected.

Exelon, Generation and subsidiaries of Generation entered into a Master Agreement with EDF, EDF Inc. (EDFI) (a subsidiary of EDF) and CENG that will result in Generation operating the CENG nuclear generation fleet. The Master Agreement was entered into with the expectation that it will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the agreement is subject to a number of uncertainties, including whether CENG can be integrated into Generation in an efficient, effective and timely manner. Integration will take place, and additional agreements will be signed, upon receipt of regulatory approvals for the transfer of CENG s nuclear operating licences to Generation.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of Generation s business, processes and systems or inconsistencies in standards, controls, procedures, practices, policies, valuation models, and compensation arrangements. In addition, Generation may have difficulty addressing possible differences in corporate cultures and management philosophies. Any of these circumstances could adversely affect Generation s ability to achieve the anticipated benefits of the agreement as and when expected. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect Generation s future business, financial condition, operating results and prospects.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd, PECO and BGE

None.

ITEM 2. PROPERTIES

Generation

The following table describes Generation s interests in net electric generating capacity by station at December 31, 2013:

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Limerick	Mid-Atlantic	Sanatoga, PA	2		Uranium	Base-load	2,316
Peach Bottom	Mid-Atlantic	Delta, PA	2	50	Uranium	Base-load	1,167[(f)]
Salem	Mid-Atlantic	Lower Alloways Creek Township, NJ	2	42.59	Uranium	Base-load	1,006[(f)]
Calvert Cliffs	Mid-Atlantic	Lusby, MD	2	50.01	Uranium	Base-load	878[(f)(h)]
Three Mile Island	Mid-Atlantic	Middletown, PA	1		Uranium	Base-load	837
Keystone	Mid-Atlantic	Shelocta, PA	2	41.98	Coal	Base-load	714[(f)]
Oyster Creek	Mid-Atlantic	Forked River, NJ	1		Uranium	Base-load	625[(e)]
Conowingo	Mid-Atlantic	Darlington, MD	11		Hydroelectric	Base-load	572
Conemaugh	Mid-Atlantic	New Florence, PA	2	31.28	Coal	Base-load	532[(f)]
Criterion	Mid-Atlantic	Oakland, MD	28		Wind	Base-load	70
Colver	Mid-Atlantic	Colver Twp., PA	1	25	Waste Coal	Base-load	26[(f)]
Solar Horizons	Mid-Atlantic	Emmitsburg, MD	1		Solar	Base-load	16
Solar New Jersey 2	Mid-Atlantic	Various	2		Solar	Base-load	10
Solar New Jersey 1	Mid-Atlantic	Various	4		Solar	Base-load	10
Solar Maryland	Mid-Atlantic	Various	9		Solar	Base-load	9
Solar Federal	Mid-Atlantic	Trenton, NJ	1		Solar	Base-load	5
Solar Maryland 2	Mid-Atlantic	Pocomoke, MD	2		Solar	Base-load	4
Solar New York	Mid-Atlantic	Various	1		Solar	Base-load	3
Solar New Jersey 3	Mid-Atlantic	Middle Township, NJ	5		Solar	Base-load	2
Muddy Run	Mid-Atlantic	Drumore, PA	8		Hydroelectric	Intermediate	1,070
Eddystone 3, 4	Mid-Atlantic	Eddystone, PA	2		Oil/Gas	Intermediate	760
Safe Harbor	Mid-Atlantic	Conestoga, PA	12	66.7	Hydroelectric	Intermediate	278[(f)]
Croydon	Mid-Atlantic	West Bristol, PA	8		Oil	Peaking	391
Perryman	Mid-Atlantic	Belcamp, MD	5		Oil/Gas	Peaking	353
Handsome Lake	Mid-Atlantic	Kennerdell, PA	5		Gas	Peaking	268
Riverside	Mid-Atlantic	Baltimore, MD	4		Oil/Gas	Peaking	228
Westport	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	115
Notch Cliff	Mid-Atlantic	Baltimore, MD	8		Gas	Peaking	118
Richmond	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	98
Gould Street	Mid-Atlantic	Baltimore, MD	1		Gas	Peaking	97
Philadelphia Road	Mid-Atlantic	Baltimore, MD	4		Oil	Peaking	61
Eddystone	Mid-Atlantic	Eddystone, PA	4		Oil	Peaking	60
Fairless Hills	Mid-Atlantic	Fairless Hills, PA	2		Landfill Gas	Peaking	60
Delaware	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	56
Southwark	Mid-Atlantic	Philadelphia, PA	4		Oil	Peaking	52
Falls	Mid-Atlantic	Morrisville, PA	3		Oil	Peaking	51
Moser	Mid-Atlantic	Lower PottsgroveTwp., PA	3		Oil	Peaking	51
Chester	Mid-Atlantic	Chester, PA	3		Oil	Peaking	39
Schuylkill	Mid-Atlantic	Philadelphia, PA	2		Oil	Peaking	30
Salem	Mid-Atlantic	Lower Alloways Creek Twp, NJ	1	42.59	Oil	Peaking	16[(f)]
Pennsbury	Mid-Atlantic	Morrisville, PA	2		Landfill Gas	Peaking	6
Keystone	Mid-Atlantic	Shelocta, PA	4	41.98	Oil	Peaking	4[(f)]
Conemaugh	Mid-Atlantic	New Florence, PA	4	31.28	Oil	Peaking	3[(f)]
Total Mid-Atlantic							13,067
Braidwood	Midwest	Braidwood, IL	2		Uranium	Base-load	2,353
LaSalle	Midwest	Seneca, IL	2		Uranium	Base-load	2,327
Byron	Midwest	Byron, IL	2		Uranium	Base-load	2,319
Dresden	Midwest	Morris, IL	2		Uranium	Base-load	1,843

Quad Cities	Midwest	Cordova, IL	2	75	Uranium	Base-load	1,403[(f)]
Clinton	Midwest	Clinton, IL	1		Uranium	Base-load	1,067
Michigan Wind 2	Midwest	Sanilac Co., MI	50		Wind	Base-load	90

Station [(a)]	Region	Location	No. of Units	Percent Owned [(b)]	Primary Fuel Type	Primary Dispatch Type [(c)]	Net Generation Capacity (MW) [(d)]
Beebe	Midwest	Gratiot Co., MI	34		Wind	Base-load	81
Michigan Wind 1	Midwest	Huron Co., MI	46		Wind	Base-load	69
Harvest 2	Midwest	Huron Co., MI	33		Wind	Base-load	59
Harvest	Midwest	Huron Co., MI	32		Wind	Base-load	53
Ewington	Midwest	Jackson Co., MN	10	99	Wind	Base-load	21[(f)]
Marshall	Midwest	Lyon Co., MN	9	99	Wind	Base-load	19[(f)]
City Solar	Midwest	Chicago, IL	1		Solar	Base-load	8
Norgaard	Midwest	Lincoln Co., MN	7	99	Wind	Base-load	9[(f)]
AgriWind	Midwest	Bureau Co., IL	4	99	Wind	Base-load	8[(f)]
Cisco	Midwest	Jackson Co., MN	4	99	Wind	Base-load	8[(f)]
Brewster	Midwest	Jackson Co., MN	6	94-99	Wind	Base-load	6[(f)]
Wolf	Midwest	Nobles Co., MN	5	99	Wind	Base-load	6[(f)]
CP Windfarm	Midwest	Faribault Co., MN	2		Wind	Base-load	4
Blue Breezes	Midwest	Faribault Co., MN	2		Wind	Base-load	3
Cowell	Midwest	Pipestone Co., MN	1	99	Wind	Base-load	2[(f)]
Solar Ohio	Midwest	Toledo, OH	2		Solar	Base-load	1
Southeast Chicago	Midwest	Chicago, IL	8		Gas	Peaking	296
Total Midwest							12,055
Whitetail	ERCOT	Laredo, TX	57		Wind	Base-load	91
Wolf Hollow 1, 2, 3	ERCOT	Granbury, TX	3		Gas	Intermediate	704
Mountain Creek 8	ERCOT	Dallas, TX	1		Gas	Intermediate	565
Colorado Bend	ERCOT	Wharton, TX	1		Gas	Intermediate	498
Quail Run	ERCOT	Odessa, TX	1		Gas	Intermediate	488
Handley 3	ERCOT	Fort Worth, TX	1		Gas	Intermediate	395
Handley 4, 5	ERCOT	Fort Worth, TX	2		Gas	Peaking	870
Mountain Creek 6, 7	ERCOT	Dallas, TX	2		Gas	Peaking	240
LaPorte	ERCOT	Laporte, TX	4		Gas	Peaking	152
Total ERCOT							4,003
Holyoke Solar	New England	Various	2		Solar	Base-load	5
Solar Massachusetts	New England	Various	5		Solar	Base-load	3
Solar Net Metering	New England	Uxbridge, MA	1		Solar	Base-load	2
Solar Connecticut	New England	Various	2		Solar	Base-load	1
Mystic 8, 9	New England	Charlestown, MA	2		Gas	Intermediate	1,418
Fore River	New England	North Weymouth, MA	1		Gas	Intermediate	726
Mystic 7	New England	Charlestown, MA	1		Oil/Gas	Intermediate	575
Wyman	New England	Yarmouth, ME	1	5.9	Oil	Intermediate	36[(f)]
Medway	New England	West Medway, MA	3		Oil/Gas	Peaking	117
Framingham	New England	Framingham, MA	3		Oil	Peaking	33
New Boston	New England	South Boston, MA	1		Oil	Peaking	16
Mystic Jet	New England	Charlestown, MA	1		Oil	Peaking	9
Total New England							2,941
Nine Mile Point	New York	Scriba, NY	2	50.01[(h)]	Uranium	Base-load	833[(f)(h)]
Ginna	New York	Ontario, NY	1	50.01	Uranium	Base-load	288[(f)(h)]
Total New York							1,121
AVSR	Other	Lancaster, CA	1		Solar	Base-load	198[(g)]
Shooting Star	Other	Greensburg, KS	65		Wind	Base-load	104
Exelon Wind 4	Other	Gruver, TX	38		Wind	Base-load	80
Bluegrass Ridge	Other	King City, MO	27		Wind	Base-load	57
Conception	Other	Barnard, MO	24		Wind	Base-load	50
Cow Branch	Other	Rock Port, MO	24		Wind	Base-load	50
Mountain Home	Other	Glenns Ferry, ID	20		Wind	Base-load	42
High Mesa	Other	Elmore Co., ID	19		Wind	Base-load	40
Echo 1	Other	Echo, OR	21	99	Wind	Base-load	35[(f)]
Sacramento PV Energy	Other	Sacremento, CA	4		Solar	Base-load	30
Cassia	Other	Buhl, ID	14		Wind	Base-load	29
Wildcat	Other	Lovington, NM	13		Wind	Base-load	27

Sunnyside	Other	Sunnyside, UT	1	50	Waste Coal	Base-load	26[f]
Echo 2	Other	Echo, OR	10		Wind	Base-load	20

Station [a]	Region	Location	No. of Units	Percent Owned [b]	Primary Fuel Type	Primary Dispatch Type [c]	Net Generation Capacity (MW) [d]
Tuana Springs	Other	Hagerman, ID	8		Wind	Base-load	17
Greensburg	Other	Greensburg, KS	10		Wind	Base-load	13
Echo 3	Other	Echo, OR	6	99	Wind	Base-load	10[f]
Exelon Wind 1	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 2	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 3	Other	Gruver, TX	8		Wind	Base-load	10
Exelon Wind 5	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 6	Other	Texhoma, TX	8		Wind	Base-load	10
Exelon Wind 7	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 8	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 9	Other	Sunray, TX	8		Wind	Base-load	10
Exelon Wind 10	Other	Dumas, TX	8		Wind	Base-load	10
Exelon Wind 11	Other	Dumas, TX	8		Wind	Base-load	10
High Plains	Other	Panhandle, TX	8	99.5	Wind	Base-load	10[f]
Threemile Canyon	Other	Boardman, OR	6		Wind	Base-load	10
Solar Arizona	Other	Various	20		Solar	Base-load	29
Outback Solar	Other	Christmas Valley, OR	1		Solar	Base-load	6
Loess Hills	Other	Rock Port, MO	4		Wind	Base-load	5
Denver Airport Solar	Other	Denver, CO	1		Solar	Base-load	4
California PV Energy	Other	Ontario, CA	2		Solar	Base-load	3
Solar California	Other	Various	4		Solar	Base-load	2
Hillabee	Other	Alexander City, AL	1		Gas	Intermediate	670
Malacha	Other	Muck Valley, CA	1	50	Hydroelectric	Intermediate	15[f][i]
West Valley	Other	Salt Lake City, UT	5		Gas	Peaking	185
Grand Prairie	Other	Alberta, Canada	1		Gas	Peaking	75
SEGS 4, 5, 6	Other	Boron, CA	3	4.2-12.2	Solar	Peaking	8[f]
Total Other							1,950
Total							35,137

(a) All nuclear stations are boiling water reactors except Braidwood, Byron, Calvert Cliffs, Ginna, Salem and Three Mile Island, which are pressurized water reactors.
(b) 100%, unless otherwise indicated.
(c) Base-load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower-efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(d) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. Wind and solar facilities reflect name plate capacity.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Expected capacity upon project completion is 230MW. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(h) 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. Generation also has a unit-contingent PPA with CENG under which it purchases 85% of the nuclear plant output owned by CENG that is not sold to third parties under the pre-existing PPAs through 2014.
(i) In February 2014, Generation sold its remaining stake in Malacha.

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

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

ComEd

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

Transmission and Distribution

ComEd s higher voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,642
138,000	2,292

ComEd s electric distribution system includes 35,491 circuit miles of overhead lines and 30,626 circuit miles of underground lines.

First Mortgage and Insurance

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

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

PECO

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

Transmission and Distribution

PECO s high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188[(a)]
230,000	548
138,000	156
69,000	200

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

PECO s electric distribution system includes 12,989 circuit miles of overhead lines and 8,915 circuit miles of underground lines.

Gas

The following table sets forth PECO s natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	31
Distribution	6,764
Service piping	6,068
Total	12,863

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send-out capacity of 157 mmcf/day and a propane-air plant located in Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 31 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

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

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

BGE

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

Transmission and Distribution

BGE s high voltage electric transmission lines owned and in service at December 31, 2013 were as follows:

Voltage (Volts)	Circuit Miles
500,000	218
230,000	322
138,000	54
115,000	697

BGE s electric distribution system includes 9,391 circuit miles of overhead lines and 15,933 circuit miles of underground lines.

Gas

The following table sets forth BGE s natural gas pipeline miles at December 31, 2013:

	Pipeline Miles
Transmission	163
Distribution	7,054
Service piping	6,146
Total	13,363

BGE has an LNG facility located in Baltimore, Maryland that has a storage capacity of 1,055 mmcf and a send-out capacity of 332 mmcf/day, an LNG facility located in Westminster, Maryland that has a storage capacity of 6 mmcf and a send-out capacity of 6 mmcf/day, and a propane-air plant located in Baltimore, Maryland, with a storage capacity of 546 mmcf and a send-out capacity of 85 mmcf/day. In addition, BGE owns 12 natural gas city gate stations and 20 direct pipeline customer delivery points at various locations throughout its gas service territory.

Property Insurance

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

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

Exelon, Generation, ComEd, PECO and BGE

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 Notes 3 and 22 of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd, PECO and BGE

Not Applicable to the Registrants.

PART II

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

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

Exelon

Exelon s common stock is listed on the New York Stock Exchange. As of January 31, 2014, there were 857,419,806 shares of common stock outstanding and approximately 129,928 record holders of common stock.

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

	2013				2012			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 30.59	$ 32.42	$ 37.80	$ 34.56	$ 37.50	$ 39.82	$ 39.37	$ 43.70
Low price	26.64	29.42	29.84	29.10	28.40	34.54	36.27	38.31
Close	27.39	29.64	30.88	34.48	29.74	35.58	37.62	39.21
Dividends	0.310	0.310	0.310	0.525	0.525	0.525	0.525	0.525

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 2009 through 2013.

This performance chart assumes:

- $100 invested on December 31, 2008 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and

- All dividends are reinvested.

Generation

As of January 31, 2014, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2014, there were 127,016,904 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, 2014, 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, 2014, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

BGE

As of January 31, 2014, there were 1,000 outstanding shares of common stock, without par value, of BGE, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd, PECO and BGE

Dividends

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

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

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

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

BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE s equity ratio would be below 48% as calculated pursuant to the MDPSC s ratemaking precedents or (b) BGE s senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE s preference stock have not been paid.

At December 31, 2013, Exelon had retained earnings of $10,358 million, including Generation s undistributed earnings of $3,613 million, ComEd s retained earnings of $750 million consisting of retained earnings appropriated for future dividends of $2,389 million, partially offset by $1,639 million of unappropriated retained deficits, PECO s retained earnings of $649 million, and BGE s retained earnings of $1,005 million.

The following table sets forth Exelon s quarterly cash dividends per share paid during 2013 and 2012:

	2013				2012			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$ 0.310	$ 0.310	$ 0.310	$ 0.525	$ 0.525	$ 0.525	$ 0.525	$ 0.525

The following table sets forth Generation s quarterly distributions and ComEd s and PECO s quarterly common dividend payments:

	2013				2012			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 75	$ 76	$ 263	$ 211	$ 242	$ 493	$ 291	$ 600
ComEd	55	55	55	55	10	10	10	75
PECO	83	83	83	83	85	86	85	87

First Quarter 2014 Dividend. On January 28, 2014, the Exelon Board of Directors declared a first quarter 2014 regular quarterly dividend of $0.31 per share on Exelon s common stock payable on March 10, 2014, to shareholders of record of Exelon at the end of the day on February 14, 2014.

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)	2013	2012 [(a)]	2011	2010	2009
Statement of Operations data:					
Operating revenues	$ 24,888	$ 23,489	$ 19,063	$ 18,644	$ 17,318
Operating income	3,656	2,380	4,479	4,726	4,750
Income from continuing operations	1,729	1,171	2,499	2,563	2,706
Income from discontinued operations					1

Net income	1,729	1,171	2,499	2,563	2,707
Earnings per average common share (diluted):					
Income from continuing operations	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Net income	$ 2.00	$ 1.42	$ 3.75	$ 3.87	$ 4.09
Dividends per common share	$ 1.46	$ 2.10	$ 2.10	$ 2.10	$ 2.10
Average shares of common stock outstanding diluted	860	819	665	663	662

(a) The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

	December 31,				
(In millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Balance Sheet data:					
Current assets	$ 10,137	$ 10,140	$ 5,713	$ 6,398	$ 5,441
Property, plant and equipment, net	47,330	45,186	32,570	29,941	27,341
Noncurrent regulatory assets	5,910	6,497	4,518	4,140	4,872
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	13,922	14,113	9,569	9,136	8,901
Total assets	$ 79,924	$ 78,561	$ 54,995	$ 52,240	$ 49,180
Current liabilities	$ 7,728	$ 7,791	$ 5,134	$ 4,240	$ 4,238
Long-term debt, including long-term debt to financing trusts	18,271	18,346	12,189	12,004	11,385
Noncurrent regulatory liabilities	4,388	3,981	3,627	3,555	3,492
Other deferred credits and other liabilities	26,597	26,626	19,570	18,791	17,338
Preferred securities of subsidiary		87	87	87	87
Non-controlling interest	15	106	3	3	
BGE preference stock not subject to mandatory redemption	193	193			
Shareholders equity	22,732	21,431	14,385	13,560	12,640
Total liabilities and shareholders equity	$ 79,924	$ 78,561	$ 54,995	$ 52,240	$ 49,180

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)	**2013**	**2012 (a)**	**2011**	**2010**	**2009**
Statement of Operations data:					
Operating revenues	$ 15,630	$ 14,437	$ 10,447	$ 10,025	$ 9,703
Operating income	1,664	1,120	2,875	3,046	3,295
Net income	1,060	558	1,771	1,972	2,122

(a) The 2012 financial results only include the operations of Constellation from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012.

	December 31,				
(In millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Balance Sheet data:					
Current assets	$ 6,439	$ 6,211	$ 3,217	$ 3,087	$ 3,360
Property, plant and equipment, net	20,111	19,531	13,475	11,662	9,809
Other deferred debits and other assets	14,682	14,939	10,741	9,785	9,237

Total assets	$ 41,232	$ 40,681	$ 27,433	$ 24,534	$ 22,406
Current liabilities	$ 3,867	$ 4,097	$ 2,144	$ 1,843	$ 2,262
Long-term debt	7,168	7,455	3,674	3,676	2,967
Other deferred credits and other liabilities	17,455	16,464	12,907	11,838	10,385
Non-controlling interest	17	108	5	5	2
Member s equity	12,725	12,557	8,703	7,172	6,790
Total liabilities and member s equity	$ 41,232	$ 40,681	$ 27,433	$ 24,534	$ 22,406

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)	**2013**	**2012**	**2011**	**2010**	**2009**
Statement of Operations data:					
Operating revenues	$ 4,464	$ 5,443	$ 6,056	$ 6,204	$ 5,774
Operating income	954	886	982	1,056	843
Net income	249	379	416	337	374

	December 31,				
(In millions)	**2013**	**2012**	**2011**	**2010**	**2009**
Balance Sheet data:					
Current assets	$ 1,540	$ 1,775	$ 2,188	$ 2,151	$ 1,579
Property, plant and equipment, net	14,666	13,826	13,121	12,578	12,125
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	933	666	699	947	1,096
Other deferred debits and other assets	4,354	4,013	4,005	3,351	3,272
Total assets	$ 24,118	$ 22,905	$ 22,638	$ 21,652	$ 20,697
Current liabilities	$ 2,048	$ 1,655	$ 2,071	$ 2,134	$ 1,597
Long-term debt, including long-term debt to financing trusts	5,264	5,521	5,421	4,860	4,704
Noncurrent regulatory liabilities	3,512	3,229	3,042	3,137	3,145
Other deferred credits and other liabilities	5,766	5,177	5,067	4,611	4,369
Shareholders equity	7,528	7,323	7,037	6,910	6,882
Total liabilities and shareholders equity	$ 24,118	$ 22,905	$ 22,638	$ 21,652	$ 20,697

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)	**2013**	**2012**	**2011**	**2010**	**2009**
Statement of Operations data:					
Operating revenues	$ 3,100	$ 3,186	$ 3,720	$ 5,519	$ 5,311
Operating income	666	623	655	661	697
Net income	395	381	389	324	353
Net income on common stock	388	377	385	320	349

(In millions)	2013	2012	December 31, 2011	2010	2009
Balance Sheet data:					
Current assets	$ 906	$ 1,094	$ 1,243	$ 1,670	$ 1,006
Property, plant and equipment, net	6,384	6,078	5,874	5,620	5,297
Noncurrent regulatory assets	1,448	1,378	1,216	968	1,834
Other deferred debits and other assets	879	803	823	727	882
Total assets	$ 9,617	$ 9,353	$ 9,156	$ 8,985	$ 9,019
Current liabilities	$ 891	$ 1,158	$ 1,145	$ 1,163	$ 939
Long-term debt, including long-term debt to financing trusts	2,131	1,831	1,781	2,156	2,405
Noncurrent regulatory liabilities	629	538	585	418	317
Other deferred credits and other liabilities	2,901	2,757	2,620	2,278	2,706
Preferred securities		87	87	87	87
Shareholders equity	3,065	2,982	2,938	2,883	2,565
Total liabilities and shareholders equity	$ 9,617	$ 9,353	$ 9,156	$ 8,985	$ 9,019

BGE

The selected financial data presented below has been derived from the audited consolidated financial statements of BGE. This data is qualified in its entirety by reference to and should be read in conjunction with BGE s Consolidated Financial Statements and ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations.

(In millions)	2013	For the Years Ended December 31, 2012	2011	2010	2009
Statement of Operations data:					
Operating revenues	$ 3,065	$ 2,735	$ 3,068	$ 3,541	$ 3,646
Operating income	449	132	314	350	268
Net income	210	4	136	147	91
Net income (loss) attributable to common shareholder	197	(9)	123	134	78

(In millions)	2013	2012 [(a)]	December 31, 2011 [(a)]	2010 [(a)]	2009 [(a)]
Balance Sheet data:					
Current assets	$ 1,011	$ 980	$ 969	$ 1,012	$ 1,205
Property, plant and equipment, net	5,864	5,498	5,132	4,754	4,470
Noncurrent regulatory assets	524	522	551	566	602
Other deferred debits and other assets	462	506	551	545	386
Total assets	$ 7,861	$ 7,506	$ 7,203	$ 6,877	$ 6,663
Current liabilities	$ 827	$ 980	$ 734	$ 728	$ 753
Long-term debt, including long-term debt to financing trusts and variable interest entities	2,199	1,969	2,186	2,060	2,141
Noncurrent regulatory liabilities	204	214	201	192	188
Other deferred credits and other liabilities	2,076	1,985	1,781	1,634	1,434
Preference stock not subject to mandatory redemption	190	190	190	190	190
Shareholders equity	2,365	2,168	2,111	2,073	1,939
Non-controlling interest					18

Total liabilities and shareholders equity	$ 7,861	$ 7,506	$ 7,203	$ 6,877	$ 6,663

(a) BGE retrospectively reclassified certain regulatory assets and regulatory liabilities to conform to the current year presentation.

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

Exelon

Executive Overview

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

Generation, whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.

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

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

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

Exelon has nine reportable segments consisting of Generation s six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions in Generation), ComEd, PECO and BGE. See Note 24 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon s reportable segments.

Through its business services subsidiary BSC, Exelon provides its operating subsidiaries with a variety of support services at cost. The costs of these services are directly charged or allocated to the applicable operating segments. Additionally, the results of Exelon s corporate operations include costs for corporate governance and interest costs and income from various investment and financing activities.

Exelon s consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, 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 and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

Financial Results. The following consolidated financial results reflect the results of Exelon for year ended December 31, 2013 compared to the same period in 2012. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

Results in 2013 were unfavorably impacted at Generation by continuing declines in realized power and gas prices, in part driven by the abundance of natural gas supply, continued sluggish demand and subsidized renewable generation; only partially offset by improved returns at the utilities, and the realization of additional post-merger synergies and operational excellence across all businesses. Generation s financial results continue to be challenged by low natural gas prices, and by the impacts of excess generation from subsidized renewable energy, flat load growth and distorted market designs, especially in its Midwest markets.

	The Years Ended December 31, 2013						2012	Favorable (Unfavorable)
	Generation	ComEd	PECO	BGE	Other	Exelon	Exelon	Variance
Operating revenues	$ 15,630	$ 4,464	$ 3,100	$ 3,065	$ (1,371)	$ 24,888	$ 23,489	$ 1,399
Purchased power and fuel	8,197	1,174	1,300	1,421	(1,368)	10,724	10,157	(567)
Revenue net of purchased power and fuel [(a)]	7,433	3,290	1,800	1,644	(3)	14,164	13,332	832
Other operating expenses								
Operating and maintenance	4,534	1,368	748	634	(14)	7,270	7,961	691
Depreciation and amortization	856	669	228	348	52	2,153	1,881	(272)
Taxes other than income	389	299	158	213	36	1,095	1,019	(76)
Total other operating expenses	5,779	2,336	1,134	1,195	74	10,518	10,861	343
Equity in earnings/(losses) of unconsolidated affiliates	10					10	(91)	101
Operating income	1,664	954	666	449	(77)	3,656	2,380	1,276
Other income and (deductions)								
Interest expense, net	(357)	(579)	(115)	(122)	(183)	(1,356)	(928)	(428)
Other, net	368	26	6	17	56	473	346	127
Total other income and (deductions)	11	(553)	(109)	(105)	(127)	(883)	(582)	(301)
Income (loss) before income taxes	1,675	401	557	344	(204)	2,773	1,798	975
Income taxes	615	152	162	134	(19)	1,044	627	(417)
Net income (loss)	1,060	249	395	210	(185)	1,729	1,171	558
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	(10)		7	13		10	11	1
Net income (loss) on common stock	$ 1,070	$ 249	$ 388	$ 197	$ (185)	$ 1,719	$ 1,160	$ 559

(a) The Registrants evaluate operating performance using the measure of revenue net of purchased power and fuel expense. The Registrants believe that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Exelon s net income on common stock was $1,719 million for the year ended December 31, 2013 as compared to $1,160 million for the year ended December 31, 2012, and diluted earnings per average common share were $ 2.00 for the year ended December 31, 2013 as compared to $1.42 for the year ended December 31, 2012.

Operating revenues net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $832 million as compared to 2012. The year-over-year increase in operating revenue net of purchased power and fuel expense reflects the inclusion of Constellation and BGE s results for the full period in 2013 and was primarily due to the following favorable factors:

Decrease in Generation s amortization expense for the acquired energy contracts recorded at fair value at the merger date of $610 million;

Increase in BGE s revenue net of purchased power and fuel expense of $278 million, primarily as a result of the inclusion of BGE s results for the full period in 2013, accrual of the residential customer rate credit that was a condition of the MDPSC s approval of Exelon s merger with Constellation in 2012, and the impact of the MDPSC approved electric and natural gas distribution rate increases that became effective February 23, 2013;

Increase in Generation s revenue net of purchased power and fuel of $159 million on other activities, including proprietary trading, retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of customer sited solar facilities, primarily due to the addition of Constellation; and

Increase in ComEd s revenue net of purchased power expense of $154 million primarily due to increased distribution revenue due to recovery of increased costs and capital investment and higher allowed ROE pursuant to the formula rate under EIMA and the enactment of Senate Bill 9.

The year-over-year increase in operating revenue net of purchased power and fuel expense was partially offset by the following unfavorable factors:

Decrease in Generation s electric revenue net of purchased power and fuel expense of $565 million primarily due to lower realized energy prices, lower load volume and increased nuclear fuel expense, partially offset by higher capacity revenue, increased nuclear volumes, and lower energy supply costs as a result of the integration of the energy generation and load serving businesses following the merger;

Reduced revenue net of purchased power and fuel at Generation of $136 million in 2013 associated with the Maryland Clean Coal assets that were sold in November 2012 and lost compensation on the reliability-must-run program with PJM for retired fossil generating assets that expired on May 31, 2012; and

Decrease in PECO s revenue net of purchased power and fuel expense of $11 million primarily due to the decrease in effective rates due to increased usage per customer across all customer classes, decreased cost recovery for energy efficiency and demand response programs, decreased gross receipts tax revenue, and the customer refund in 2013 of the tax cash benefit related to gas property distribution repairs.

Operating and maintenance expense decreased by $691 million as compared to 2012 primarily due to the following favorable factors:

Decrease in operating and maintenance expense associated with the generating assets retired or divested during 2012 of $442 million;

Costs incurred in March 2012 of $216 million and $195 million as part of the Maryland order approving the merger and a settlement with the FERC, respectively;

Decrease in Constellation merger and integration costs of $201 million in 2013; and

Decrease in uncollectible accounts expense of $58 million at ComEd resulting from the timing of regulatory cost recovery and customers purchasing electricity from competitive electric generation suppliers.

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

Increase in labor, other benefits, contracting and materials costs of $298 million, primarily due to the addition of BGE and Constellation for the full period in 2013; and

Long-lived asset impairments and related charges of $174 million in 2013, primarily related to Generation s cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

Depreciation and amortization expense increased by $272 million primarily due to the addition of BGE and Constellation for the full period in 2013, BGE s and Constellation s plant balances in 2012, ongoing capital expenditures across the operating companies, the completion of wind and solar facilities placed into service in the second half of 2012 and in 2013 at Generation, and increased regulatory asset amortization related to higher MGP remediation expenditures and higher costs for energy efficiency and demand response programs at ComEd and BGE, respectively.

The favorable increase in Equity in earnings/loss of unconsolidated affiliates of $101 million was primarily due to higher net income from Generation s equity investment in CENG in 2013 compared to the same period in 2012 and lower amortization of the basis difference of Generation s ownership interest in CENG recorded at fair value in connection with the merger.

Interest expense increased by $428 million primarily due to an increase in interest expense at ComEd related to the remeasurement of Exelon s like-kind exchange tax position in the first quarter of 2013, an increase in debt obligations as a result of the merger and an increase in project financing at Generation in 2013.

Exelon s effective income tax rates for the years ended December 31, 2013 and 2012 were 37.6% and 34.9%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2013 and 2012, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon s adjusted (non-GAAP) operating earnings for the year ended December 31, 2013 were $2,149 million, or $2.50 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,330 million, or $2.85 per diluted share, for the same period in 2012. 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 as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2013 as compared to 2012:

	December 31,			
	2013		2012	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income	$ 1,719	$ 2.00	$ 1,160	$ 1.42
Mark-to-Market Impact of Economic Hedging Activities [a]	(310)	(0.35)	(310)	(0.38)
Unrealized Net Gains Related to NDT Fund Investments [b]	(78)	(0.09)	(56)	(0.07)
Plant Retirements and Divestitures [c]	(13)	(0.02)	236	0.29
Asset Retirement Obligation [d]	7	0.01	1	
Merger and Integration Costs [e]	87	0.08	257	0.31
Other Acquisition Costs [f]			3	
Reassessment of State Deferred Income Taxes [g]	4		(117)	(0.14)
Amortization of Commodity Contract Intangibles [h]	347	0.41	758	0.93
Amortization of the Fair Value of Certain Debt [i]	(7)	(0.01)	(9)	(0.01)
Remeasurement of Like-Kind Exchange Tax Position [j]	267	0.31		
Long-Lived Asset Impairment [k]	110	0.14		
Maryland Commitments [l]			227	0.28
FERC Settlement [m]			172	0.21
Midwest Generation Bankruptcy Charges [n]	16	0.02	8	0.01
Adjusted (non-GAAP) Operating Earnings	$ 2,149	$ 2.50	$ 2,330	$ 2.85

(a) Reflects the impact of (gains) losses for the years ended December 31, 2013 and 2012, respectively, on Generation s economic hedging activities (net of taxes of $201 million and $200 million, respectively). In order to better align the impacts of economic hedging with the underlying business activity (e.g. the sale of power and/or the use of fuel), these unrealized (gains) losses are excluded from operating earnings until the transactions are realized. See Note 12 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s hedging activities.

(b) Reflects the impact of unrealized gains for the years ended December 31, 2013 and 2012, respectively, on Generation s NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(144) million and $(132) million, respectively). See Note 15 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s NDT fund investments.

(c) Reflects the impacts associated with the sale or retirement of generating stations in the years ended December 31, 2013 and 2012 (net of taxes of $4 million and $106 million, respectively). See Results of Operations Generation for additional detail related to the generating unit retirements.

(d) Primarily reflects the impact of an increase in Generation s asset retirement obligation for asbestos at retired fossil plants for the year ended December 31, 2013 (net of taxes of $(5) million). Primarily reflects the impact of an increase in Generation s decommissioning obligation for spent nuclear fuel at retired nuclear units for the year ended December 31, 2012 (net of taxes of $(1) million).

(e) Reflects certain costs incurred in the years ended December 31, 2013 and 2012 (net of taxes of $33 million and $161 million, respectively) associated with the merger, including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) integration initiatives, certain pre-acquisition contingencies, and CENG transaction costs, partially offset in 2013 by a one-time benefit pursuant to the BGE 2012 electric and gas distribution rate case order for the recovery of previously incurred integration costs. See Note 4 Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the year ended 2012 associated with various acquisitions (net of taxes of $2 million).

(g) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of changes in forecasted apportionment in 2013 and as a result of the merger in 2012. See Note 14 Income Taxes of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects the non-cash impact for the years ended December 31, 2013 and 2012 (net of taxes of $219 million and $491 million, respectively) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 4 Merger and Acquisitions of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects the non-cash amortization of certain debt for the years ended December 31, 2013 and 2012 (net of taxes of $5 million and $6 million, respectively) recorded at fair value at the Constellation merger date which was retired in the second quarter of 2013. See Note 4 Merger and Acquisitions of the Combined Notes to Consolidated Financial Statements for additional information.

(j) Reflects a non-cash charge to earnings for the year ended December 31, 2013 (net of taxes of $102 million) resulting from the first quarter 2013 remeasurement of a like-kind exchange tax position taken on ComEd s 1999 sale of fossil generating assets. See Note 14 of the Combined Notes to the Consolidated Financial statements for additional information.

(k) Reflects 2013 impairment and related charges to earnings for the year ended December 31, 2013 (net of taxes of $69 million) primarily related to Generation s cancellation of nuclear uprate projects and the impairment of certain wind generating assets.

(l) Reflects costs incurred for the year ended December 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(m) Reflects costs incurred for the year ended December 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation s pre-merger hedging and risk management transactions. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

(n) Reflects costs incurred to establish estimated liabilities for the years ended December 31, 2013 and December 31, 2012 (net of taxes of $10 million and $5 million, respectively) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.

As discussed above, Exelon has incurred and will continue to incur costs associated with the Constellation merger, including meeting the various commitments set forth by regulators and agreed-upon with other interested parties as part of the merger approval process, and integrating the former Constellation businesses into Exelon.

For the year ended December 31, 2013, expense has been recognized for costs incurred to achieve the merger, prior to consideration of regulatory accounting treatment, as follows:

	Pre-tax Expense Twelve Months Ended December 31, 2013				
Merger and Integration Costs:	**Generation [a]**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Employee-Related [b]	48	4	3	1	58
Other [c]	58	12	6	5	84
Total	$ 106	$ 16	$ 9	$ 6	$ 142

	Pre-tax Expense Twelve Months Ended December 31, 2012				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE [a]**	**Exelon [a]**
Maryland Commitments	35			139	328
Employee-Related [b]	138	24	11	24	207
Other [c]	167	17	6	7	211
Transaction [d]	$	$	$	$	$ 58
Total	$ 340	$ 41	$ 17	$ 170	$ 804

(a) For Exelon, Generation and BGE, includes the operations of the acquired businesses from the date of the merger March 12, 2012 through the year ended December 31, 2013.

(b) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd established regulatory assets of $2 million and $21 million for the years ended December 31, 2013 and December 31, 2012, respectively. BGE established regulatory assets of $0 million and $22 million for the years ended December 31, 2013 and December 31, 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.

(c) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $9 million and $15 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs. BGE established a regulatory asset of $12 million and $0 million for the years ended December 31, 2013 and December 31, 2012, respectively, for certain other merger and integration costs.

(d)

External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.

As of December 31, 2013, Exelon expects to incur total additional Constellation merger-related expenses in 2014 and 2015 of approximately $34 million.

Pursuant to the conditions set forth by the MDPSC in its approval of the merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately $1 billion. The direct investment includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation s competitive energy businesses. On March 20, 2013, Generation signed a twenty-year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once required approvals are received and financing condition is satisfied, construction of the building will commence. The building is expected to be ready for occupancy in two years following commencement of construction. The direct investment estimate also includes $625 million in expenditures relating to the development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years).

Exelon s Strategy and Outlook for 2014 and Beyond

Exelon s value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline.

On March 12, 2012, the Exelon and Constellation merger was completed. The merger creates incremental strategic value by matching Exelon s clean generation fleet with Constellation s leading customer-facing platform, as well as creating economies of scale through expansion across the energy value chain. Exelon supports customer switching to alternative electric generation suppliers and the addition of Constellation s competitive retail operations provides another outlet for Exelon to grow its business in competitive markets.

Generation s electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation s regional and technological footprint. 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 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 mitigate the current challenging conditions in competitive energy markets.

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. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately $15 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

Exelon s financial priorities are to maintain investment grade credit metrics at each of Exelon, Generation, ComEd, PECO and BGE, and to return value to Exelon s shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power 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 prices of natural gas and coal, which drive the market prices that Generation can obtain for the output of its power plants, (2) the rate of expansion of subsidized low-carbon generation in the markets in which Generation s output is sold, (3) the effects on energy demand due to factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these market pricing issues.

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. Since the third quarter of 2011, forward natural gas prices for 2014 and 2015 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

Subsidized Generation. The rate of expansion of subsidized low-carbon generation such as wind and solar energy in the markets in which Generation s output is sold can negatively impact wholesale power prices, and in turn, Generation s results of operations.

Various states have implemented or proposed legislation, regulations or other policies to subsidize new generation development, which may result in artificially depressed wholesale energy and capacity prices. For example, the New Jersey legislature enacted into law in January 2011, the Long Term capacity Pilot Program (LCAPP). LCAPP provides eligible generators with 15-year fixed contracts for the sale of capacity in the PJM capacity market. Under LCAPP, the local utilities in New Jersey are required to pay (or receive) the difference between generators receive in the capacity market and the price guaranteed under the 15 year contract. New Jersey ultimately selected three proposals to participate in LCAPP and build new generation in the state. In addition, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. CPV has subsequently sought to extend that date. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV s contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court. On October 25, 2013, the U.S. District Court in New Jersey issued a judgment order finding that the New Jersey legislation violates the Supremacy Clause of the United States Constitution and the New Jersey SOCA contract is unenforceable. Similarly, on October 24, 2013, the U.S. District Court in Maryland issued a judgment order finding that the MDPSC s Order directing BGE and two other Maryland electric distribution companies to enter into a CfD violates the Supremacy Clause of the United States Constitution, as described in Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements. In addition, on October 1, 2013, a Maryland State Circuit Court upheld the MDPSC Orders as being within the MDPSC s statutory authority under Maryland state law. This decision is separate from the judgment in the federal litigation that the MDPSC Order is unconstitutional and the CfD unenforceable under federal law. The federal judgment, if upheld, would prevent enforcement of the CfD even if the Circuit Court decision stands. The non-prevailing parties have sought appeals in federal appellate court in both the New Jersey and

Maryland federal litigation. Finally, on October 23, 2013, the New Jersey state court dismissed the New Jersey state proceeding without prejudice, subject to the final outcome of the New Jersey federal litigation.

As required under their contracts, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM s capacity market auctions held in May 2012 and 2013. In addition, CPV has announced its intention to move forward with construction of its New Jersey plant, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon s market driven position. While the U.S. District Court decisions in Maryland and New Jersey are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR), could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon s market driven position and could have a significant effect on Exelon s financial results of operations, financial position and cash flows.

PJM s capacity market rules include a MOPR, which is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, as described above, Exelon does not believe that the existing MOPR will work effectively with respect to generator developers who have a state-sponsored subsidy and has concerns with certain other aspects of PJM s rules related to the capacity auction. Accordingly, Exelon is working with other market stakeholders on several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sponsored subsidy contracts, excessive imported capacity resources and certain limited availability demand response resources) cannot inappropriately affect capacity auction prices in PJM.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Maryland Order.

Exelon remains active in advocating for competitive markets, opposing policies that ask either taxpayers or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

Energy Demand. The continued tepid economic environment and growing energy efficiency initiatives have limited the demand for electricity across each of the Exelon utility companies. ComEd is projecting load volumes to decrease by 0.2% in 2014 compared to 2013, while PECO and BGE are projecting an increase of 0.3% and 0.6%, respectively, in 2014 compared to 2013.

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. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use their retail operations to hedge generation output. These factors have adversely affected overall gross margins and profitability in Generation s retail operations.

Strategic Policy Alignment

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

Exelon s board of directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward energy prices and weaker financial expectations, among other factors, approved a revised dividend policy going forward. The first quarter dividend was paid on March 8, 2013 to shareholders of record on February 19, 2013 and was based on Exelon s previous dividend of $2.10 per share on an annualized basis. The second, third and fourth quarter dividends were based on Exelon s new dividend policy of $0.31 per share quarterly dividend ($1.24 per share on an annualized basis). All future quarterly dividends require approval by Exelon s board of directors.

Exelon and Generation evaluate the economic viability of each of their generating units on an ongoing basis. Decisions regarding the future of economically challenged generating assets will be based primarily on the economics of continued operation of the individual plants. If Exelon and Generation do not see a path to sustainable profitability in any of their plants, Exelon and Generation will take steps to retire those plants to avoid sustained losses. Retirement of plants could materially affect Exelon s and Generation s results of operations, financial position, and cash flows through among other things, potential impairment charges, accelerated depreciation and decommissioning expenses over the plants remaining useful lives, and ongoing reductions to operating revenues, operating and maintenance expenses, and capital expenditures.

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 2014 and 2015. 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, 2013, the percentage of expected generation hedged for the major reportable segments was 92%-95%, 62%-65% and 30%-33% for 2014, 2015, and 2016, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation s sales of energy to ComEd, PECO and BGE relating to their respective retail load obligations. 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 coal, 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 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 60% of Generation s uranium concentrate requirements from 2014 through 2018 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon s and Generation s results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate such exposure through regulatory mechanisms that allow them to recover procurement costs from retail customers.

Growth Opportunities

Exelon is currently pursuing growth in both the utility and generation businesses focused primarily on smart meter and smart grid initiatives at the utilities and on renewables development and the nuclear uprate program at Generation. The utilities also anticipate making significant future investments in infrastructure modernization and improvement initiatives. Management continually evaluates growth opportunities aligned with Exelon s existing businesses in electric and gas distribution, electric transmission, generation, customer supply of electric and natural gas products and services, and natural gas exploration and production activities, leveraging Exelon s expertise in those areas.

Transmission Development Project. Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop an extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost and scope of the project are dependent on a number of factors, including RTO requirements, interregional transmission planning process requirements, state siting requirements, routing of the line, and equipment and commodity costs. Exelon and AEP are currently pursuing the project and other segments that are electrically equivalent in nature for inclusion in interregional planning process between PJM and MISO; if approved through that process, the project would then need to be approved through the respective planning processes of PJM and MISO.

On July 18, 2011, RITELine Illinois and RITELine Indiana filed at FERC for incentive rates and a formula rate for the RITE Line project. On October 14, 2011, FERC issued an order on the incentive and formula rate filing. The order grants a base rate of return on common equity of 9.9%, plus a 50 basis point adder for the project being in a RTO and a 100 basis point adder for the risks and challenges of the project, resulting in a total rate of return on common equity of 11.4%. The order grants a hypothetical capital structure of 45% debt and 55% equity until any part of the project enters commercial operations. The order also grants 100% recovery for construction work in progress, 100% recovery for abandonment, if the line is abandoned through no fault of the RITELine developers, and the ability to treat pre-construction costs as a regulatory asset. All incentives, including the abandonment incentive, are contingent on inclusion of the project in the PJM RTEP. The RITELine companies filed for rehearing on several rate of return on common equity issues and argued that the right to collect abandoned costs should not be subject to the project being included in the RTEP. The RITELine companies also made a compliance filing as called for in the October 14, 2011 Order. FERC accepted this filing on March 16, 2012.

Smart Meter and Smart Grid Initiatives.

ComEd s Smart Meter and Smart Grid Investments. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan. On June 5, 2013, the ICC issued an interim order approving ComEd s accelerated AMI deployment plan consistent with the provisions of Senate Bill 9. The deployment plan provides for the installation of 4 million electric smart meters, of which more than 60,000 meters were installed by the end of 2013.

PECO s Smart Meter and Smart Grid Investments. In 2010, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan, under which PECO will install more than 1.6 million smart meters. PECO plans to spend up to a total of $595 million and $120 million on its smart meter and smart grid infrastructure, respectively, of which $200 million will be funded by SGIG.

BGE Smart Grid Initiative. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE which includes the planned installation of 2 million electric and gas smart meters at an expected total cost of approximately $480 million, before considering the $200 million SGIG for smart grid and other related initiatives.

See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which is developing, building, operating, and maintaining the project. The first portion of the project began operations in December 2012, with six additional blocks coming online in 2013. Exelon has been informed by First Solar of issues relating to delays in the certification of certain components relating to the final two blocks of the project, which will delay commercial operation of these two blocks until the first half of 2014. The delay will not have a material financial effect on Exelon. Exelon expects the project to be in full commercial operation in the first half of 2014. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA with Pacific Gas & Electric Company for the full output of the plant, which has been approved by the CPUC. Upon completion, the facility will add 230 MWs to Generation s renewable generation fleet. Total capitalized costs for the facility are expected to be approximately $1.1 billion. Total capitalized costs incurred through December 31, 2013 were approximately $968 million. In addition, Generation constructed and placed into service 400 MWs of additional wind generation in 2012 at a cost of $710 million and another 50 MW will be added to Generation s wind portfolio in 2014 with the expansion of its Beebe project in Michigan, the output of which will be fully contracted under a 20-year PPA.

Nuclear Uprate Program. Generation is engaged in individual projects as part of a planned power uprate program across its nuclear fleet. When economically viable, the projects take advantage of new production and measurement technologies, new materials and application of expertise gained from a half-century of nuclear power operations. Based on ongoing reviews, the nuclear uprate implementation plan was adjusted during 2013 to cancel certain projects. The Measurement Uncertainty Recapture uprate projects at the Dresden and Quad Cities nuclear stations were cancelled as a result of the cost of additional plant modifications identified during final design work which, when combined with then current market conditions, made the projects not economically viable. Additionally, the market conditions prompted Generation to cancel the previously deferred extended power uprate projects at the LaSalle and Limerick nuclear stations. During 2013, Generation recorded a pre-tax charge to operating and maintenance expense and interest expense of approximately $111 million and $8 million, respectively, to accrue remaining costs and reverse the previously capitalized costs.

Under the nuclear uprate program, Generation has placed into service projects representing 316 MWs of new nuclear generation at a cost of $952 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s consolidated balance sheets. At December 31, 2013, Generation has capitalized $203 million to construction work in progress within property, plant and equipment for nuclear uprate projects expected to be placed in service by the end of 2016, consisting of 200 MWs of new nuclear generation, that are in the installation phase across four nuclear stations; Peach Bottom in Pennsylvania and Byron, Braidwood and Dresden in Illinois. The remaining spend associated with these projects is expected to be approximately $300 million through the end of 2016. Generation believes that it is probable that these projects will be completed. If a project is expected not to be completed as planned, previously capitalized costs will be reversed through earnings as a charge to operating and maintenance expense and interest.

Liquidity

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of $0.4 billion.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2013, approximately 30%, or $2.5 billion, of the Registrants aggregate total commitments were with European banks. The credit facilities include $8.4 billion in aggregate total commitments of which $6.6 billion was available as of December 31, 2013. There were no borrowings under the Registrants credit facilities as of December 31, 2013. See Note 13 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

February 5, 2014 Winter Ice Storm. On February 5, 2014, a winter storm which brought a mix of snow, ice and freezing rain to the region interrupted electric service delivery to nearly 715,000 customers in PECO s service territory. Restoration efforts are continuing and will include significant costs associated with employee overtime, support from other utilities and incremental equipment, contracted tree trimming crews and supplies. PECO estimates that restoration efforts will result in $60 million to $80 million of incremental operating and maintenance expense and $30 million to $40 million of incremental capital expenditures for the first quarter of 2014.

Tax Matters

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

Environmental Legislative and Regulatory Developments.

Exelon supports the promulgation of certain environmental regulations by the U.S. EPA, including air, water and waste controls for electric generating units. See discussion below for further details. The air and waste regulations will have a disproportionate adverse impact on fossil-fuel power plants, requiring significant expenditures of capital and variable operating and maintenance expense, and will likely result in the retirement of older, marginal facilities. Due to their low emission generation portfolios, Generation and CENG will not be significantly directly affected by these regulations, representing a competitive advantage relative to electric generators that are more reliant on fossil-fuel plants. Various bills have been introduced in the U.S. Congress that would prohibit or impede the U.S. EPA s rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air Quality. In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a review of the current 2008 ozone NAAQS that is expected to result in a proposed revision of the ozone NAAQS sometime in fall 2014. These updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. Until the U.S. EPA re-issues CSAPR, Exelon cannot determine the impacts of the rule, including any that would impact power prices. In June 2013, the U.S. Supreme Court granted the U.S. EPA s petition to review the D.C. Circuit Court s CSAPR decision. Oral argument was held on December 10, 2013. A decision is expected sometime during 2014.

On December 16, 2011, the U.S. 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. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court will not occur until 2014. The outcome of the appeal, and its impact on power plant operators investment and retirement decisions, is uncertain.

The cumulative impact of these air regulations could be to require power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO_2 and acid gases, and selective catalytic reduction technology for NO_x. Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS by January 1, 2015. In addition, Keystone already has SCR and Flue-gas desulfurization (FGD) controls in place.

On January 15, 2013, EPA issued a final rule for NSPS and National Emissions Standards for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE NESHAP/NSPS). The final rule allows diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but requires units that operate over 15 hours to burn low sulfur fuel and report key engine information. The final rule eliminates after May 2014 the 50 hour exemption for peak shaving and other non-emergency demand response that was included in the proposed rule and, therefore, is not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction.

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. The U.S. EPA is addressing the issue of carbon dioxide (CO2) emissions regulation for new and existing electric generating units through the New Source Performance Standards (NSPS) under Section 111 of the Clean Air Act. Pursuant to President

Obama s June 25, 2013 memorandum to U.S. EPA, the Agency re-proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO2 emissions for new fossil-fuel electric generating units, particularly coal-fired units. Under the President s memorandum, the U.S. EPA is also required to propose a Section 111(d) rule no later than June 1, 2014 to establish CO2 emission regulations for existing stationary sources. Pursuant to the President s Climate Action Plan, the U.S. EPA re-proposed regulations for the GHG emissions from new fossil fueled power plants on September 20, 2013. The U.S. EPA is also expected to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon s overall low-carbon generation portfolio results would benefit.

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.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by November 4, 2013; on October 30, 2013 the U.S. EPA invoked the *force majeure* provision of the Settlement Agreement to extend the final rule deadline until November 20, 2013 due to the early October 2013 federal government shutdown. The U.S. EPA and the plaintiffs have stated that the deadline will be extended again for a brief period, but have not yet agreed on a date. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

It is unknown at this time whether the final regulations will require closed-cycle cooling. The economic viability of Generation s facilities without closed-cycle cooling water systems will be called into question by any requirement to construct cooling towers. Should the final rule not require the installation of cooling towers, and retain the flexibility afforded the state permitting agencies in applying a cost-benefit test and to consider site-specific factors, the impact of the rule would be minimized even though the costs of compliance could be material to Generation.

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA s intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation s plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania, which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has entered into a Consent Decree which requires that a final rule be issued by December 19, 2014.

See Note 22 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

Japan Earthquake and Tsunami and the Industry s Response. On March 11, 2011, Japan experienced a 9.0 magnitude earthquake and ensuing tsunami that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co.

In July 2011, an NRC Task Force formed in the aftermath of the Fukushima Daiichi events issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The NRC staff and the Task Force concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force s report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant s spent nuclear fuel pools.

In 2012, the NRC authorized its staff to issue three immediately effective orders (Tier 1 orders) to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In addition, in 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors (BWR) with Mark I and Mark II containment structures. In summary, through the initial and/or subsequent orders and the NRC approved implementation guidance, the Tier 1 orders currently: (1) require licensees to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the core and spent fuel pool and to maintain containment integrity until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) provide requirements for vents for BWR s with Mark I and Mark II containments to remain functional during severe accident conditions including the ability to vent the containment following core damage; and (3) require licensees to install instrumentation to provide a reliable indication of water level in the spent fuel pool. Finally, the NRC has directed the NRC staff to produce a technical evaluation to support rulemaking that considers filtering and performance-based strategies as options for BWR s with Mark I and Mark II containments. The NRC staff must then develop a final rule by March 2017.

Additionally, in 2012, the NRC had issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. The nuclear industry proposed, and the NRC approved, an augmented approach to the seismic hazard analysis to accommodate industry wide availability of qualified technical resources needed to perform the required analysis. The NRC approved this augmented approach.

Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for the period from 2014 through 2018 is expected to be between approximately $350 million and $375 million of capital and $50 million of operating expense, as previously anticipated in Generation s planning projections. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation s current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors, for further discussion of the risk factors.

Financial Reform Legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was enacted in July 2010. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing, exchange trading, margin requirements, and other transparency requirements. The Dodd-Frank Act, however, also preserves the ability of end users in the energy industry to hedge their risks. In April 2012, the CFTC issued its rule defining swap dealers and major swap participants. Exelon has determined that it will conduct its commercial business in a manner that does not require registration as a swap dealer or major swap participant. Notwithstanding, there are additional rulemakings that have not yet been issued, including the capital and margin rules, which will further define the scope of the regulations and provide clarity as to the impact on the Registrants business, as well as to potential new opportunities. Depending on these final rules, the Registrants could be subject to significant new obligations.

The proposed regulations addressing collateral and capital requirements and exchange margin cash postings, when final, could require Generation to increase collateral requirements or cash postings in lieu of letters of credit currently issued to collateralize Swaps. Exelon had previously estimated that it could be required to make up to $1 billion of additional collateral postings under its bilateral credit lines. Given the swap dealer and the major swap participant definitions will not apply to Generation, the actual amount of collateral postings that will be required may be lower than Exelon s previous expectations due to the following factors: (a) the majority of Generation s physical wholesale portfolio does not meet the final CFTC Swap definition; (b) there will be minimal incremental costs associated with Generation s positions that are currently cleared and subject to exchange margin; and (c) Generation will not be a swap dealer or major swap participant and proposed capital requirements applicable to these entities will not apply to Generation.

The actual level of collateral required will depend on many factors, including but not limited to market conditions, the outcome of final margin rules for Swaps, the extent of its trading activity in Swaps, and Generation s credit ratings. Nonetheless, Generation has adequate credit facilities and flexibility in its hedging program to meet its anticipated collateral requirements estimated based on conservative assumptions.

In addition, the new regulations will impose new and ongoing compliance and infrastructure costs on Generation, which may amount to several million dollars per year.

Exelon and Generation continue to monitor the rulemaking procedures and cannot predict the ultimate outcome that the financial reform legislation will have on their results of operations, cash flows or financial position.

ComEd, PECO and BGE could also be subject to various Dodd-Frank Act requirements to the extent they enter into Swap transactions. However, at this time, management of ComEd, PECO and BGE do not expect to be materially affected by this legislation.

Energy Infrastructure Modernization Act. Since 2011, ComEd s distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation.

Formula Rate Tariff

In March 2013, the Illinois legislature passed Senate Bill 9 to clarify the intent of EIMA on the three issues decided in the Rehearing Order: an allowed return on ComEd s pension asset; the use of year-end rather than average rate base and capital structure in the annual reconciliation; and the use of ComEd s weighted average cost of capital interest rate rather than a short-term debt rate to apply to the annual reconciliation. On May 22, 2013, Senate Bill 9 became effective after the Illinois legislature overrode the Governor s veto of that Bill. On June 5, 2013, the ICC approved ComEd s updated distribution formula rate structure to reflect the impacts of Senate Bill 9.

In October 2013, the ICC opened an investigation (the Investigation), in response to a complaint filed by the Illinois Attorney General, to change the formula rate structure by requesting three changes: the elimination of the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance, the netting of associated accumulated deferred income taxes against the annual reconciliation balance in calculating interest, and the use of average rather than year-end rate base for determining any ROE collar adjustment. On November 26, 2013, the ICC issued its final order in the Investigation, rejecting two of the proposed changes but accepting the proposed change to eliminate the income tax gross-up on the weighted average cost of capital used to calculate interest on the annual reconciliation balance. The accepted change became effective in January 2014, and is estimated to reduce ComEd s 2014 revenue by approximately $8 million. ComEd and intervenors requested rehearing, however all rehearing requests were denied by the ICC. ComEd and intervenors have filed appeals with the Illinois Appellate Court. ComEd cannot predict the results of any such appeals. See 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Annual Reconciliation

On May 30, 2013, ComEd updated its revenue requirement allowed in the December 2012 Order to reflect the impacts of Senate Bill 9, which resulted in a reduction to the current revenue requirement in effect of $14 million. The rates took effect in July 2013.

2013 Filing. On April 29, 2013, ComEd filed its annual distribution formula rate, which was updated on May 30, 2013 to reflect the impacts of Senate Bill 9. The ICC s final order, issued on December 19, 2013, increased the revenue requirement by $341 million, reflecting an increase of $160 million for the initial revenue requirement for 2013 and an increase of $181 million for the annual reconciliation for 2012. The rate increase was set using an allowed return on capital of 6.94% (inclusive of an allowed return on common equity of 8.72%). The rates took effect in January 2014. ComEd requested a rehearing on specific issues, which was denied by the ICC. ComEd and intervenors also filed appeals. ComEd cannot predict the results of any such appeals. See 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make

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refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd s results of operations and cash flows.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC s *Mobile-Sierra* standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of such PJM Transmission Owners that the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs; and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC s order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd s, PECO s and BGE s financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC s March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC s rejection of their Mobile-Sierra and related arguments. The compliance filing was made on July 22, 2013. On January 16, 2014, FERC issued an order stating that PJM s filing while subject to further orders, is effective as of January 1, 2014.

FERC Transmission Complaint. On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. As of December 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base return on equity, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base return on equity to 8.7%, the annual impact would be a reduction in revenues of approximately $10 million. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

The Maryland Strategic Infrastructure Development and Enhancement Program. In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. Under the new law, following a proceeding before the MDPSC and with the MDPSC s approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. The new surcharge rates are expected to take effect in the first quarter of 2014. BGE cannot predict the outcome of this proceeding or how much of the requested plan and related surcharge the MDPSC will approve. The MDPSC held evidentiary hearings on BGE s proposed plan and surcharge on November 12, 2013 through November 14, 2013. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE s plan and surcharge. BGE must submit a list detailing specific projects planned for 2014 to the MDPSC for approval within 30 days of the decision. Upon approval of the project list by the MDPSC, BGE will be able to implement the surcharge rates on gas customers bills. The new surcharges are expected to take effect in the second quarter of 2014. In addition, BGE will be subject to an annual independent audit to review plan performance and progress. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

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 discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the accounting policies described below require significant judgment in their application, or estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations (Exelon and Generation)

Generation s ARO associated with decommissioning its nuclear units was $4.9 billion at December 31, 2013. 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 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 or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its 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.

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.

Probabilistic Cash Flow Models. Generation s probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are assigned to alternative decommissioning approaches which assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for

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unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations) decommissioning. Probabilities assigned to the timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals. Generation s probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal, which Generation assumed would begin in 2025 in 2013 and 2012. The SNF acceptance date was based on management s estimates of the amount of time required for the DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 22 of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. The current NRC license for Oyster Creek expires in 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019. As a result of this decision the expected economic life of Oyster Creek was reduced by 10 years to correspond to Exelon s current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. Generation has successfully secured 20-year operating license renewal extensions for ten of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation s applications for an operating license extension have been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining nine operating nuclear units. Generation s assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for ten units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $210 million per unit as of December 31, 2013. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation s ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

Discount Rates. The probability-weighted estimated future cash flows using these various scenarios are discounted using credit-adjusted, risk-free rates (CARFR) applicable to the various businesses in which each of the nuclear units originally operated. The accounting guidance required Generation to establish an ARO at fair value at the time of the initial adoption of the current accounting standard. Subsequent to the initial adoption, the ARO is adjusted for changes to estimated costs, timing of future cash flows and modifications to decommissioning assumptions, as described above.

Under the current accounting framework, the ARO is not required or permitted to be re-measured for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation s future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $4.9 billion to approximately $5.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon s and Generation s Consolidated Balance Sheets at December 31, 2013 at fair value of approximately $8.1 billion and have an estimated targeted annual pre-tax return of 5.9 % to 6.7 %.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had

Generation used the 2012 CARFRs rather than the 2013 CARFRs in performing its third quarter 2013 ARO update, Generation would have reduced the ARO by approximately $10 million as compared to the actual decrease to the ARO of $140 million; and ii) if the CARFR used in performing the third quarter 2013 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have decreased by $300 million and increased $40 million, respectively, as compared to the actual decrease of $140 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items 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 will change as well. As an example, Exelon had a historical increase of approximately $670 million in the value of the ARO which was driven by Generation modifying the assumed timing of the DOE acceptance of SNF for disposal from 2020 to 2025. The modification of the assumed DOE acceptance date affected the calculation of the ARO in isolation as follows; i) the change in the timing of DOE acceptance of SNF increased the total number of years in which decommissioning activities are estimated to occur, by five years on average, thereby increasing the total expected nominal cash flows required to decommission the units; ii) the nominal cash flows were subjected to additional escalation as a result of the extension of the decommissioning period increasing the total estimated costs required to decommission the units; and iii) the escalated cash flows were discounted at the then current CARFRs which had dramatically decreased during that time period.

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

Change in ARO Assumption		**Increase (Decrease) to ARO at December 31, 2013**
Cost escalation studies		
Uniform increase in escalation rates of 25 basis points	$	560
Probabilistic cash flow models		
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$	190
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	290
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$	430
Extend the estimated date for DOE acceptance of SNF to 2030	$	50
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$	(230)
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$	600

For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 15 of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

As of December 31, 2013, Exelon s and ComEd s carrying amount of goodwill was approximately $2.6 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit

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below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or operating component and is the level at which goodwill is tested for impairment. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd s business 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.

Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd s earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

ComEd performed a quantitative assessment as of November 1, 2013, for its 2013 annual goodwill impairment assessment. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

While neither the interim nor the annual assessments indicated an impairment of ComEd s goodwill, certain assumptions used to estimate the fair value of ComEd are highly sensitive to changes. Adverse regulatory actions, such as early termination of EIMA, or changes in significant assumptions, including discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd s business, and the fair value of debt, could potentially result in a future impairment of ComEd s goodwill, which could be material. Based on the results of the annual goodwill test performed as of November 1, 2013, the estimated fair value of ComEd would have needed to decrease by more than 10% for ComEd to fail the first step of the impairment test. See Note 1 Significant Accounting Policies, Note 10 Intangible Assets and Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

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

Unamortized Energy Assets and Liabilities (Exelon and Generation)

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4 Mergers and Acquisitions and Note 10 Intangible Assets for further discussion.

Impairment of Long-lived Assets (Exelon, Generation, ComEd, PECO and BGE)

Exelon, Generation, ComEd, PECO and BGE 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. Conditions that could have an adverse impact on the cash flows and fair value of the long-lived assets are deteriorating business climate, including current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others.

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

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. 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 frequently do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires adjustment, the resulting fair market value would be different. As such, 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. An impairment determination would require the affected Registrant to reduce either the long-lived asset or asset group, including any intangible contract assets and liabilities, and current period earnings by the amount of the impairment.

Generation evaluates unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved gas property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience indicates a decline in carrying value below fair value.

Exelon holds investments in coal-fired plants in Georgia and Texas subject to long-term leases. The investments are accounted for as direct financing lease investments. The investments represent the estimated residual values of the leased assets at the end of the respective lease terms. On an annual basis, Exelon reviews the estimated residual values of its direct financing lease investments and records an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments using a discounted cash flow analysis, which takes into consideration the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates.

Generation also evaluates its equity method investments to determine whether or not they are impaired based on whether the investment has experienced a decline in value that is not temporary in nature. Additionally, if one of Generation s equity method investments recognize an impairment, Generation would record its proportionate share of that impairment loss through its equity earnings (losses) of unconsolidated affiliates. Generation would also evaluate the investment for a decline in value at that time that is not temporary in nature.

See Note 8 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 (Exelon, Generation, ComEd, PECO and BGE)

The Registrants have significant investments in electric generation assets and electric and natural gas transmission and distribution assets. Depreciation of these assets is generally provided over their estimated service lives on a straight-line basis using the composite method. The estimation of service lives requires management judgment regarding the period of time that the assets will be in use. As circumstances warrant, the estimated service lives are reviewed to determine if any changes are needed. Depreciation rates incorporate assumptions on interim retirements based on actual historical retirement experience. To the extent interim retirement patterns change, this could have a significant impact on the amount of depreciation expense recorded in the income statement. Changes to depreciation estimates resulting from a change in the estimated end of service lives could have a significant impact on the amount of depreciation expense recorded in the income statement. See Note 1 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.

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation s operating nuclear generating stations except for Oyster Creek. While Generation has

received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates annually the estimated service lives of its generating facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation s extension or reduction of the estimated service lives could have a significant effect on Generation s results of operations. Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd completed a depreciation study in 2014 and filed the updated depreciation rates with both FERC and the ICC in January 2014. This is expected to result in the implementation of new depreciation rates effective first quarter 2014.

PECO is required to file a depreciation rate study at least every five years with the PAPUC. In April 2010, PECO filed a depreciation rate study with the PAPUC for both its electric and gas assets, which resulted in the implementation of new depreciation rates effective January 1, 2010 for electric transmission assets and January 1, 2011 for electric distribution and gas assets.

The MDPSC does not mandate the frequency or timing of BGE s depreciation studies. In December 2006, BGE filed revised depreciation rates with the MDPSC for both its electric distribution and gas assets. Revisions to depreciation rates from this filing were finalized July 1, 2010.

Defined Benefit Pension and Other Postretirement Benefits (Exelon, Generation, ComEd, PECO and BGE)

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. 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.

The measurement of the plan obligations and costs of providing benefits under Exelon s defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions 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. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 16 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term expected rate of return on plan assets assumption used in calculating pension costs was 7.50%, 7.50%, and 8.00% for 2013, 2012 and 2011, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 6.45%, 6.68%, and 7.08% in 2013, 2012 and 2011, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability-driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. See Note 16 Retirement Benefits of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon s asset allocations. Exelon used an EROA of 7.00% and 6.59% to estimate its 2014 pension and other postretirement benefit costs, respectively.

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

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants pension and other postretirement benefit plans for the year ended December 31, 2013 were 6.73% and 11.41%, respectively, compared to an expected long-term return assumption of 7.50% and 6.45%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations were 4.80% and 4.90%, respectively, at December 31, 2013. The discount rates at December 31, 2013 represent weighted-average rates for both pension and other postretirement benefit plans. At December 31, 2013 and 2012, 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 distributions 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.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 4.80% and 4.90% to estimate its 2014 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers.

One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer s postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon changed the manner in which it will receive prescription drug subsidies beginning in 2013.

The Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Effective in 2002, Constellation amended its other postretirement benefit plans for all subsidiaries other than Nine Mile Point by capping retiree medical coverage for future retirees who were under the age of 55 on January 1, 2002 at 2002 levels. Therefore, the excise tax is not expected to have a material impact on the legacy Constellation other postretirement benefit plans. However, certain key assumptions are required to estimate the impact of the excise tax on the other postretirement obligation for legacy Exelon plans, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Health Care Cost Trend Rate. Assumed health care cost trend rates have a significant effect on the costs reported for Exelon s other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed an initial health care cost trend rate of 6.50% for 2013, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

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

Actuarial Assumption	**Change in Assumption**	**Pension**	**Other Postretirement Benefits**	**Total**
Change in 2013 cost:				
Discount rate [(a)]	0.5%	$ (63)	$ (34)	$ (97)
	(0.5%)	68	48	116
EROA	0.5%	(68)	(10)	(78)
	(0.5%)	68	10	78
Health care cost trend rate	1.00%	N/A	90	90
	(1.00%)	N/A	(62)	(62)
Change in benefit obligation at December 31, 2013:				
Discount rate [(a)]	0.5%	(904)	(297)	(1,201)
	(0.5%)	965	318	1,283
Health care cost trend rate	1.00%	N/A	858	858
	(1.00%)	N/A	(607)	(607)

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

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.8 years, 11.9 years, and 12.1 years for the years ended December 31, 2013, 2012 and 2011, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.7 years, 8.9 years and 6.6 years for the years ended December 31, 2013, 2012 and 2011, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 9.8 years, 10.1 years and 8.7 years for the years ended December 31, 2013, 2012 and 2011, respectively.

Regulatory Accounting (Exelon, ComEd, PECO and BGE)

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2013, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated Statements of Operations and could be material. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd, PECO and BGE 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 ComEd s, PECO s and BGE s jurisdictions, and factors such as changes in applicable regulatory and political environments. Furthermore, Exelon, ComEd, PECO and BGE make other judgments related to the financial statement impact of their regulatory environments, such as the types of adjustments to rate base that will be acceptable to regulatory bodies, if any, to which costs will be recoverable through rates. Refer to the revenue recognition discussion below for additional information on the annual revenue reconciliations associated with ComEd s distribution formula rate tariff, pursuant to EIMA, and FERC-approved transmission formula rate tariffs for ComEd and BGE. Additionally, estimates are made in accordance with the authoritative guidance for contingencies as to the amount of revenues billed under certain regulatory orders that may ultimately be refunded to customers upon finalization of applicable regulatory or judicial processes. These assessments are based, to the extent possible, on past relevant experience with regulatory bodies in ComEd s, PECO s and BGE s jurisdictions, known circumstances specific to a particular matter and hearings held with the applicable regulatory body. If the assessments and estimates made by Exelon, ComEd, PECO and BGE are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

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

Accounting for Derivative Instruments (Exelon, Generation, ComEd, PECO and BGE)

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd had a financial swap contract with Generation that expired May 31, 2013 and currently holds floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO and BGE have entered into derivative natural gas contracts to hedge their long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants derivative activities are in accordance with Exelon s Risk Management Policy (RMP). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants derivative instruments.

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

Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for certain derivatives that qualify for, and are elected under, the normal purchases and normal sales exception. Further, derivatives that qualify and are designated for hedge accounting are classified as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation s designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all economic hedges for commodities are recorded at fair value through earnings for the combined company. In addition, for energy-related derivatives entered into for proprietary trading purposes, changes in the fair value of the derivatives are recognized in earnings each period. For economic hedges that are not designated for hedge accounting for ComEd, PECO and BGE, changes in the fair value each period are recorded as a regulatory asset or liability.

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

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

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges are categorized in Level 2. These price quotations reflect the average of the bid-ask mid-point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The Registrant s derivatives are traded predominately at liquid trading points. The remaining derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, and assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, the model inputs are generally observable. Such instruments are categorized in Level 2. For derivatives that trade in less liquid markets with limited pricing information, the model inputs generally would include both observable and unobservable inputs. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate and Foreign Exchange Derivative Instruments. The Registrants may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve the targeted level of variable-rate debt as a percent of total debt. Additionally, the Registrants may use forward-starting interest rate swaps and treasury rate locks to lock in interest-rate levels in anticipation of future financings and floating to fixed swaps for project financing. In addition, Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the economic hedge and proprietary trading activity is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or change in market interest rates. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. The fair value of the agreements is calculated by discounting the future net cash flows to the present value based on the terms and conditions of the agreements and the forward interest rate and foreign exchange curves. As these inputs are based on observable data and valuations of similar instruments, the interest rate and foreign exchange derivatives are primarily categorized in Level 2 in the fair value hierarchy. Certain exchange based interest rate derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy.

See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Notes 11 and 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants derivative instruments.

Taxation (Exelon, Generation, ComEd, PECO and BGE)

Significant management judgment is required in determining the Registrants provisions for income taxes, primarily due to the uncertainty related to tax positions taken, as well as deferred tax assets and liabilities and valuation allowances. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of unrecognized 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 their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude 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 changes in income tax laws, the Registrants forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2013 and 2012 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies (Exelon, Generation, ComEd, PECO and BGE)

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

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on the Registrants results of operations, financial position and cash flows. See Note 22 of the Combined Notes to Consolidated Financial Statements for further information.

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

Revenue Recognition (Exelon, Generation, ComEd, PECO and BGE)

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

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

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

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

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

Unbilled Revenues. The determination of Generation s, ComEd s, PECO s and BGE s retail energy sales to individual customers is based on systematic readings of customer meters generally on a monthly basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated, and corresponding unbilled revenue is recorded. The measurement of unbilled revenue is affected by the following factors: daily customer usage measured by generation or gas throughput volume, customer usage by class, losses of energy during delivery to customers and applicable customer rates. Increases or decreases in volumes delivered to the utilities customers and favorable or unfavorable rate mix due to changes in usage patterns in customer classes in the period could be significant to the calculation of unbilled revenue. In addition, volumes may fluctuate monthly as a result of customers electing to use an alternate supplier, which could be

significant to the calculation of unbilled revenue since unbilled commodity receivables are not recorded for these customers. Changes in the timing of meter reading schedules and the number and type of customers scheduled for each meter reading date would also have an effect on the measurement of unbilled revenue; however, total operating revenues would remain materially unchanged.

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

Regulated Transmission & Distribution Revenues. ComEd s EIMA distribution formula rate tariff provides for annual reconciliations to the distribution revenue requirement. As of the balance sheet dates, ComEd has recorded its best estimates of the distribution revenue impact resulting from changes in rates that ComEd believes are probable of approval by the ICC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

ComEd s and BGE s FERC transmission formula rate tariffs provide for annual reconciliations to the transmission revenue requirements. As of the balance sheet dates, ComEd and BGE have recorded the best estimate of their respective transmission revenue impact resulting from changes in rates that ComEd and BGE believe are probable of approval by FERC in accordance with the formula rate mechanism. Estimates are based upon actual costs incurred and investments in rate base for the period and the rates of return on common equity and associated regulatory capital structure allowed under the applicable tariff. The estimated reconciliation can be affected by, among other things, variances in costs incurred and investments made and actions by regulators or courts.

Allowance for Uncollectible Accounts (Exelon, Generation, ComEd, PECO and BGE)

The allowance for uncollectible accounts reflects the Registrants best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable aging historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd s, PECO s and BGE s provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 6 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2013, 2012 and 2011 set forth below include intercompany transactions, which are eliminated in Exelon s consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2013	2012 [(a)]	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Exelon	$ 1,719	$ 1,160	$ 559	$ 2,495	$ (1,335)
Generation	1,070	562	508	1,771	(1,209)
ComEd	249	379	(130)	416	(37)
PECO	388	377	11	385	(8)
BGE	197	(9)	206	123	(132)

(a) For BGE, reflects BGE s operations for the year ended December 31, 2012. For Exelon and Generation, includes the operations of the Constellation and BGE from the date of the merger, March 12, 2012, through December 31, 2012.

Results of Operations Generation

	2013	2012 [(b)]	Favorable (unfavorable) 2013 vs. 2012 variance	2011	Favorable (unfavorable) 2012 vs. 2011 variance
Operating revenues	$ 15,630	$ 14,437	$ 1,193	$ 10,447	$ 3,990
Purchased power and fuel expense	8,197	7,061	(1,136)	3,589	(3,472)
Revenue net of purchased power and fuel expense [(a)]	7,433	7,376	57	6,858	518
Other operating expenses					
Operating and maintenance	4,534	5,028	494	3,148	(1,880)
Depreciation and amortization	856	768	(88)	570	(198)
Taxes other than income	389	369	(20)	264	(105)
Total other operating expenses	5,779	6,165	386	3,982	(2,183)
Equity in earnings (losses) of unconsolidated affiliates	10	(91)	101	(1)	(90)
Operating income	1,664	1,120	544	2,875	(1,755)
Other income and (deductions)					
Interest expense	(357)	(301)	(56)	(170)	(131)
Other, net	368	239	129	122	117
Total other income and (deductions)	11	(62)	73	(48)	(14)
Income before income taxes	1,675	1,058	617	2,827	(1,769)
Income taxes	615	500	(115)	1,056	556

Net income	1,060	558	502	1,771	(1,213)
Net loss attributable to non-controlling interest	(10)	(4)	(6)		4
Net income attributable to membership interest	$ 1,070	$ 562	$ 508	$ 1,771	$ (1,209)

(a) Generation evaluates its operating performance using the measure of revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement because it provides information that can be used to evaluate its operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

(b) Includes the operations of Constellation from the date of the merger, March 12, 2012, through December 31, 2012.

Net Income Attributable to Membership Interest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation s net income attributable to membership interest increased compared to the same period in 2012 primarily due to higher revenues, net of purchased power and fuel expense, lower operating and maintenance expense and higher earnings from Generation s interest in CENG; partially offset by impairment of certain generating assets, higher depreciation expense, higher property taxes, and higher interest expense. The increase in revenues, net or purchased power and fuel expense was primarily due to increased capacity prices and higher nuclear volume partially offset by lower realized energy prices, higher nuclear fuel costs, and lower mark-to-market gains in 2013. The decrease in operating and maintenance expense was largely due to 2012 costs associated with a settlement with FERC in 2012 and decreases in transaction costs and employee-related costs associated with the merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation s net income attributable to membership interest decreased compared to the same period in 2012 primarily due to higher operating expenses, the loss on the sale of Brandon Shores, Wagner and C.P. Crane (collectively Maryland generating stations) and the amortization of acquired energy contracts recorded at fair value at the merger date; offset by higher revenues, net of purchased power and fuel expense and favorable NDT fund performance. The increase in operating expenses was due to the addition of Constellation s financial results from March 12, 2012, costs related to a 2012 settlement with FERC and transaction and employee-related severance costs associated with the merger. The increase in revenues, net of purchased power and fuel expense was also primarily due to the merger. See Note 4 for additional information regarding the loss on the sale of three Maryland generating stations.

Revenue Net of Purchased Power and Fuel Expense

Generation s six reportable segments are based on the geographic location of its assets, and are largely representative of the footprints of an ISO/RTO and/or NERC region. Descriptions of each of Generation s six reportable segments are as follows:

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.

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

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

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

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

Other Regions not considered individually significant:

South represents operations in the FRCC, MISO s Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of

Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation s South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

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

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

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in the fourth quarter of 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities and allocates resources using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation s operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. 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 internally generated energy and fuel costs associated with tolling agreements.

For the year ended December 31, 2013 compared to 2012 and 2012 compared to 2011, Generation s revenue net of purchased power and fuel expense by region were as follows:

			2013 vs. 2012			2012 vs. 2011	
	2013	**2012 (a)**	**Variance**	**% Change**	**2011**	**Variance**	**% Change**
Mid-Atlantic (b)(f)	$ 3,270	$ 3,433	$ (163)	(4.7)%	$ 3,350	$ 83	2.5%
Midwest (c)	2,586	2,998	(412)	(13.7)%	3,547	(549)	(15.5)%
New England	185	196	(11)	(5.6)%	9	187	n.m.
New York (f)	(4)	76	(80)	(105.3)%		76	n.m.
ERCOT	436	405	31	7.7%	84	321	n.m.
Other Regions (d)	201	131	70	53.4%	(14)	145	n.m.
Total electric revenue net of purchased power and fuel expense	$ 6,674	$ 7,239	$ (565)	(7.8)%	$ 6,976	$ 263	3.8%
Proprietary Trading	(8)	(14)	6	42.9%	24	(38)	n.m.
Mark-to-market gains (losses)	504	515	(11)	(2.1)%	(288)	803	n.m.
Other (e)	263	(364)	627	n.m.	146	(510)	n.m.
Total revenue net of purchased power and fuel expense	$ 7,433	$ 7,376	$ 57	0.8%	$ 6,858	$ 518	7.6%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.

(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at merger date of $488 million and $1,098 million pre-tax for the twelve months ended December 31, 2013 and December 31, 2012, respectively.
(f) Includes $542 million and $450 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2013. Includes $487 million and $306 million of purchased power from CENG in the Mid-Atlantic and New York regions, respectively, for the year ended December 31, 2012. See Note 25 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation s supply sources by region are summarized below:

			2013 vs. 2012			2012 vs. 2011	
Supply source (GWh)	**2013**	**2012 (a)**	**Variance**	**% Change**	**2011**	**Variance**	**% Change**
Nuclear generation (b)							
Mid-Atlantic	48,881	47,337	1,544	3.3%	47,287	50	0.1%
Midwest	93,245	92,525	720	0.8%	92,010	515	0.6%
	142,126	139,862	2,264	1.6%	139,297	565	0.4%
Fossil and renewables (b)							
Mid-Atlantic (b)(d)	11,714	8,808	2,906	33.0%	7,572	1,236	16.3%
Midwest	1,478	971	507	52.2%	596	375	62.9%
New England	10,896	9,965	931	9.3%	8	9,957	n.m.
ERCOT	6,453	6,182	271	4.4%	2,030	4,152	n.m.
Other Regions (e)	6,664	5,913	751	12.7%	1,432	4,481	n.m.
	37,205	31,839	5,366	16.9%	11,638	20,201	n.m.
Purchased power							
Mid-Atlantic (c)	14,092	20,830	(6,738)	(32.3)%	2,898	17,932	n.m.
Midwest	4,408	9,805	(5,397)	(55.0)%	5,970	3,835	64.2%
New England	7,655	9,273	(1,618)	(17.4)%		9,273	n.m.
New York (c)	13,642	11,457	2,185	19.1%		11,457	n.m.
ERCOT	15,063	23,302	(8,239)	(35.4)%	7,537	15,765	n.m.
Other Regions (e)	14,931	17,327	(2,396)	(13.8)%	2,503	14,824	n.m.
	69,791	91,994	(22,203)	(24.1)%	18,908	73,086	n.m.
Total supply by region (f)							
Mid-Atlantic (g)	74,687	76,975	(2,288)	(3.0)%	57,757	19,218	33.3%
Midwest (h)	99,131	103,301	(4,170)	(4.0)%	98,576	4,725	4.8%
New England	18,551	19,238	(687)	(3.6)%	8	19,230	n.m.
New York	13,642	11,457	2,185	19.1%		11,457	n.m.
ERCOT	21,516	29,484	(7,968)	(27.0)%	9,567	19,917	n.m.
Other Regions (e)	21,595	23,240	(1,645)	(7.1)%	3,935	19,305	n.m.
Total supply	249,122	263,695	(14,573)	(5.5)%	169,843	93,852	55.3%

(a) Includes results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and does not include ownership through equity method investments (e.g., CENG).
(c) Purchased power includes physical volumes of 12,067 GWh and 9,925 GWh in the Mid-Atlantic and 12,165 GWh and 9,350 GWh in New York as a result of the PPA with CENG for the years ended December 31, 2013 and 2012 respectively.
(d)

Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger.

(e) Other Regions includes South, West and Canada, which are not considered individually significant.

(f) Excludes physical proprietary trading volumes of 8,762 GWh, 12,958 GWh and 5,742 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

(g) Includes sales to PECO through the competitive procurement process of 5,070 GWh, 7,762 GWh, and 7,041 GWh for the years ended December 31, 2013, 2012 and 2011 respectively. Sales to BGE of 5,595 GWh and 3,766 GWh were included for the years ended December 31, 2013 and 2012 respectively.
(h) Includes sales to ComEd under the RFP procurement of 7,491 GWh, 4,152 GWh and 4,731 GWh for the years ended December 31, 2013, 2012 and 2011 respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2013 as compared to the same period in 2012 and 2012 as compared to the same period in 2011.

$/MWh	2013	2012 (a)	2013 vs. 2012 % Change	2011	2012 vs. 2011 % Change
Mid-Atlantic (b)	$ 43.78	$ 44.60	(1.8)%	$ 58.00	(23.1)%
Midwest (c)	26.09	29.02	(10.1)%	35.99	(19.4)%
New England	9.97	10.19	(2.1)%	n.m.	n.m.
New York	(0.29)	6.63	(104.4)%	n.m.	n.m.
ERCOT	20.26	13.74	47.5%	8.78	56.5%
Other Regions (d)	9.31	5.64	65.0%	(3.56)	n.m.
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	$ 26.79	$ 27.45	(2.4)%	$ 41.07	(33.2)%

(a) Includes financial results for the Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes sales to PECO of $405 million (5,070 GWh), $536 million (7,762 GWh) and $508 million (7,041 GWh) for the years ended December 31, 2013, 2012 and 2011, respectively. Sales to BGE of $455 million (5,595 GWh) and $322 million (3,766 GWh) were included for the years ended December 31, 2013 and 2012 respectively. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the merger.
(c) Includes sales to ComEd of $283 million (7,491 GWh), $162 million (4,152 GWh) and $179 million (4,731 GWhs) and settlements of the ComEd swap of $230 million, $627 million and $474 million for years ended December 31, 2013, 2012 and 2011, respectively.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the years ended December 31, 2013, 2012 and 2011, respectively, and excludes the mark-to-market impact of Generation s economic hedging activities.
(f) Excludes Generation s other business activities not allocated to a region, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency, energy management and demand response. Also excludes Generation s compensation under the reliability-must-run rate schedule, the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the Exelon and Constellation merger of $488 million and $1,098 million, respectively.

Mid-Atlantic

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Mid-Atlantic of $163 million was primarily due to lower realized power prices and increased nuclear fuel costs, partially offset by the addition of Constellation in 2012, higher capacity revenues, and higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in revenue net of purchased power and fuel expense in the Mid-Atlantic of $83 million was primarily due to the addition of Constellation in 2012 and higher capacity revenues, partially offset by lower realized power prices and increased nuclear fuel costs.

Midwest

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The decrease in revenue net of purchased power and fuel expense in the Midwest of $412 million was primarily due to lower realized power prices, increased nuclear fuel costs, and lower capacity revenues, partially offset by higher nuclear revenues.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in revenue net of purchased power and fuel expense in the Midwest of $549 million was primarily due to lower capacity revenues, increased nuclear fuel costs, and lower realized power prices, partially offset by decreased congestion costs.

New England

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $11 million decrease in revenue net of purchased power and fuel expense in New England is primarily due to lower realized energy prices, partially offset by the addition of Constellation in 2012. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $187 million increase in revenue net of purchased power and fuel expense in New England was the result of the Constellation merger. Prior to the merger, New England was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

New York

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $80 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to decreased realized energy prices, partially offset by the addition of Constellation. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $76 million increase in revenue net of purchased power and fuel expense in New York was the result of the Constellation merger. Prior to the merger, New York was not a significant contributor to revenue net of purchased power and fuel expense at Generation.

ERCOT

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $31 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to increased realized energy prices and the addition of Constellation in 2012, partially offset by a decrease due to the termination of an energy supply contract with a retail power supply company that was previously a consolidated variable interest entity. As a result of the termination, Generation no longer has a variable interest in the retail supply company and ceased consolidation of the entity during the third quarter of 2013.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $321 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily as a result of the addition of Constellation in 2012, partially offset by a decrease in revenue net of purchased power and fuel expense in the legacy Generation ERCOT portfolio driven by the performance of Generation s generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $70 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the addition of Constellation in 2012, in addition to increased renewable generation.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $145 million increase in revenue net of purchased power and fuel expense in Other Regions was primarily as a result of the Constellation merger.

Mark-to-market

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $504 million in 2013 compared to gains of $515 million in 2012. See Notes 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Note 11 and 12 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The $627 million increase in other revenue net of purchased power and fuel was primarily due to reduced amortization expense of the acquired energy contracts recorded at fair value at the merger date. In addition, the increase is also attributable to results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas, and the design and construction of renewable energy facilities. These increases were partially offset by the reduction in revenues net of purchased power and fuel expense from the sale of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in the fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to increased amortization expense of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the 2012 merger with Constellation including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in fourth quarter of 2012 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2013, as compared to 2012 and 2011, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies presentations or be more useful than the GAAP information provided elsewhere in this report.

	2013	2012	2011
Nuclear fleet capacity factor [a]	94.1%	92.7%	93.3%
Nuclear fleet production cost per MWh [a]	$ 19.83	$ 19.50	$ 18.86

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC, and CENG s nuclear facilities, which are operated by CENG. Reflects ownership percentage of stations operated by Exelon.

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of planned refueling outage days in 2013, partially offset by a higher number of non-refueling outage days. For 2013 and 2012, planned refueling outage days totaled 233 and 274, respectively, and non-refueling outage days totaled 75 and 73, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs, partially offset by higher number of net MWhs generated resulted in a higher production cost per MWh during 2013 as compared to 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of non-refueling outage days, partially offset by a lower number of planned refueling outage days in 2012. For 2012 and 2011, planned refueling outage days totaled 274 and 283, respectively, and non-refueling outage days totaled 73 and 52, respectively. Higher nuclear fuel costs resulted in a higher production cost per MWh during 2012 as compared to 2011.

Operating and Maintenance Expense

The changes in operating and maintenance expense for 2013 compared to 2012, consisted of the following:

	Increase (Decrease)
Plant retirements and divestitures [a]	$ (440)
FERC settlement [b]	(195)
Constellation merger and integration costs	(107)
Maryland commitments	(35)
Bodily injury costs [c]	(16)
Nuclear refueling outage costs, including the co-owned Salem plant [d]	(14)
Corporate allocations [e]	(5)
Labor, other benefits, contracting and materials [f]	160
Impairment and related charges of certain generating assets	160
Midwest generation bankruptcy charges	11
Pension and non-pension postretirement benefits expense	5
Other	(18)

Decrease in operating and maintenance expense	$	(494)

(a) Reflects the operating and maintenance expense associated with the generating assets retired or divested during 2012.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation s prior period hedging and risk management transactions.
(c) Reflects decreased asbestos-related bodily injury expense for 2013 compared to 2012.
(d) Reflects the impact of decreased planned refueling outage days during 2013.
(e) The decrease in cost allocations during 2013 primarily reflects merger synergy savings for Exelon s corporate operations and shared service entities, partially offset by the impact of an increased share of corporate allocated costs due to the merger.
(f) Includes cost of sales of our other business activities that are not allocated to a region.

The changes in operating and maintenance expense for 2012 compared to 2011, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials [(a)]	$ 845
Loss on the sale of Maryland Clean Coal assets [(b)]	278
FERC settlement [(c)]	195
Constellation merger and integration costs	182
Corporate allocations [(d)]	175
Pension and non-pension postretirement benefits expense	76
Maryland commitments [(e)]	35
Nuclear refueling outage costs, including the co-owned Salem plant [(f)]	(52)
Other	146
Increase in operating and maintenance expense	$ 1,880

(a) Includes cost of sales of our other business activities that are not allocated to a region.
(b) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation s prior period hedging and risk management transactions.
(d) Reflects an increased share of corporate allocated costs due to the merger.
(e) Reflects costs incurred as part of the Maryland order approving the merger.
(f) Reflects the impact of decreased planned refueling outages during 2012.

Depreciation and Amortization

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities and ongoing capital additions.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the addition of Constellation facilities; and capital additions and other upgrades to legacy plants.

Taxes Other Than Income

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase was primarily due to the addition of Constellation s financial results in 2012.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase was primarily due to the addition of Constellation s financial results in 2012.

Equity in Earnings (Losses) of Unconsolidated Affiliates

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. Equity in earnings (losses) of unconsolidated affiliates increased primarily due to $50 million favorable net income generated from Exelon s equity investment in CENG and a reduction of $58 million of amortization of the basis difference in CENG recorded at fair value at the merger date.

Interest Expense

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger and increased project financing.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense is primarily due to the increase in long-term debt as a result of the merger.

Other, Net

Year Ended December 31, 2013 Compared to Year Ended December 31, 2012. The increase of $129 million in other, net primarily reflects $85 million of credit facility termination fees recorded in 2012 and increased net realized and unrealized gains related to the NDT funds of Generation s Non-Regulatory Agreement Units compared to net realized and unrealized gains in 2012, as described in the table below. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase of $117 million in other, net primarily reflects a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow, $32 million of interest income from a one-time NDT fund special transfer tax deduction in 2011, net realized and unrealized gains related to the NDT funds of Generation s Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below, offset by $85 million of credit facility termination fees recorded in 2012. Additionally, the increase reflects income related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for 2013, 2012 and 2011:

	2013	2012	2011
Net unrealized gains (losses) on decommissioning trust funds	$ 146	$ 105	$ (4)
Net realized gains (losses) on sale of decommissioning trust funds	$ 24	$ 51	$ (10)

Effective Income Tax Rate.

Generation s effective income tax rates for the years ended December 31, 2013, 2012 and 2011 were 36.7%, 47.3% and 37.4%, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations ComEd

	2013	2012	Favorable (Unfavorable) 2013 vs. 2012 Variance	2011	Favorable (Unfavorable) 2012 vs. 2011 Variance
Operating revenues	$ 4,464	$ 5,443	$ (979)	$ 6,056	$ (613)
Purchased power expense	1,174	2,307	1,133	3,035	728
Revenues net of purchased power expense [(a)]	3,290	3,136	154	3,021	115
Other operating expenses					
Operating and maintenance	1,368	1,345	(23)	1,189	(156)
Depreciation and amortization	669	610	(59)	554	(56)
Taxes other than income	299	295	(4)	296	1
Total other operating expenses	2,336	2,250	(86)	2,039	(211)
Operating income	954	886	68	982	(96)
Other income and (deductions)					
Interest expense, net	(579)	(307)	(272)	(345)	38
Other, net	26	39	(13)	29	10
Total other income and (deductions)	(553)	(268)	(285)	(316)	48
Income before income taxes	401	618	(217)	666	(48)
Income taxes	152	239	87	250	11
Net income	$ 249	$ 379	$ (130)	$ 416	$ (37)

(a) ComEd evaluates its operating performance using the measure of revenues net of purchased power expense. ComEd believes that revenues net of purchased power expense is a useful measurement because it provides information that can be used to evaluate its operational performance. In general, ComEd only earns margin based on the delivery and transmission of electricity. ComEd has included its discussion of revenues net of purchased power expense below as a complement to the financial information provided in accordance with GAAP. However, revenues net of purchased power expense is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2013, Compared to Year Ended December 31, 2012. ComEd s net income for the year ended December 31, 2013, was lower than the same period in 2012, primarily due to the remeasurement of Exelon s like-kind exchange tax position, partially offset by increased electric distribution revenues, including the impacts of Senate Bill 9, and increased transmission revenues. See Note 3 Regulatory Matters and Note 14 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd s net income for the year ended December 31, 2012, was lower than the same period in 2011, primarily due to increased operating and maintenance expenses, partially offset by increased electric distribution revenues and increased transmission revenues.

Operating Revenues Net of Purchased Power Expense

There are certain drivers of operating revenues that are fully offset by their impact on purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations in electricity procurement costs have no impact on revenues net of purchased power expense. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd s electricity procurement process.

All ComEd customers have the choice to purchase electricity from a competitive electric generation supplier. Customer choice programs do not impact ComEd s volume of deliveries, but do affect ComEd s operating revenues related to supplied energy, which is fully offset in purchased power expense. Therefore, customer choice programs have no impact on revenues net of purchased power expense.

The number of retail customers participating in customer choice programs was 2,630,185, 1,627,150 and 380,262 at December 31, 2013, 2012 and 2011, respectively, representing 68%, 43% and 10% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 81%, 65% and 56% of ComEd s retail kWh sales for the years ended December 31, 2013, 2012 and 2011, respectively. During 2012, the City of Chicago and approximately 240 Illinois municipalities, including governmental entities such as townships and counties, approved referenda regarding electric supply aggregation. The referenda allowed governmental officials to identify and sign contracts with competitive electric generation suppliers on behalf of the eligible retail customers in the community, while also allowing customers to opt-out of the municipal aggregation program. As of December 31, 2013, there are approximately 330 municipalities that have approved a municipal aggregation referendum in the ComEd service territory. As a result, approximately 69% of residential usage as of December 31, 2013 is being supplied by competitive electric generation suppliers, and ComEd estimates that over 80% of that usage resulted from municipal aggregation activities.

The changes in ComEd s revenues net of purchased power expense for the year ended 2013 compared to the same period in 2012 consisted of the following:

	Increase (Decrease)
Weather	$ (17)
Volume	(2)
Electric distribution revenues, including impacts of Senate Bill 9	168
Discrete impacts of the 2012 Distribution Rate Case Order	13
Transmission revenues	14
Regulatory required programs	20
Uncollectible accounts recovery, net	(58)
Other	16
Total increase	$ 154

Weather. The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as favorable weather conditions because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the year ended December 31, 2013, the increase in revenues net of purchased power expense was offset by unfavorable weather conditions as a result of the mild weather in 2013, compared to the same period in 2012.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd s service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd s service territory for the years ended December 31, 2013 and 2012 consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2013**	**2012**	**Normal**	**From 2012**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	6,603	5,065	6,341	30.4%	4.1%
Cooling Degree-Days	933	1,324	842	(29.5)%	10.8%

Volume. Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, for the year ended December 31, 2013, reflecting decreased average usage per residential customer as compared to the same period in 2012.

Electric Distribution Revenues. EIMA provides for a performance-based formula rate tariff, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Distribution revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants. During the year ended December 31, 2013, ComEd recorded increased revenues of $168 million, primarily due to increased capital investments, increased operating expenses, and higher allowed return on common equity, including the impacts of Senate Bill 9. These amounts exclude the discrete impacts of the 2012 Distribution Rate Case Orders, discussed separately below. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Discrete Impacts of the 2012 Distribution Rate Case Orders. On October 3, 2012, the ICC issued its final order related to ComEd s 2011 formula rate proceeding under EIMA (Rehearing Order), which reestablished ComEd s position on the return on its pension asset, resulting in an increase to revenues in 2013. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Revenues. ComEd s transmission rates are established based on a FERC-approved formula. ComEd s most recent annual formula rate update, filed in April 2013, reflects 2012 actual costs plus forecasted 2013 capital additions. Transmission revenues vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. During the year ended December 31, 2013, ComEd recorded increased revenues of $14 million primarily due to increased capital investments and higher operating expenses. See Note 3 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory Required Programs. Revenues related to regulatory required programs are recoveries from customers for costs of various legislative and regulatory programs on a full and current basis through approved regulated rates. Programs include ComEd s energy efficiency and demand response and purchased power administrative costs. An equal and offsetting amount has been reflected in operating and maintenance expense during the periods presented. See the operating and maintenance expense discussion below for additional information on included programs.

Uncollectible Accounts Recovery, Net. Represents recoveries under ComEd s uncollectible accounts tariff. See the operating and maintenance expense discussion below for additional information on this tariff.

Other. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental costs associated with MGP sites. Other revenues were higher during the year ended December 31, 2013, compared to the same period in 2012, primarily due to recoveries of increased environmental costs associated with MGP sites, for which an equal and offsetting amount expense is reflected in depreciation and amortization expense during the periods presented.

The changes in ComEd s revenues net of purchased power expense for 2012 compared to 2011 consisted of the following:

	Increase (Decrease)
Weather	$ 2
Volume	(4)
Electric distribution revenues	53
Discrete impacts of the 2012 Distribution Rate Case Order	(13