EXELON GENERATION CO LLC
Form 10-K
February 22, 2013

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, 2012

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**	23-3064219

(a Pennsylvania limited liability company)

300 Exelon Way

Kennett Square, Pennsylvania 19348-2473

(610) 765-5959

1-1839	**COMMONWEALTH EDISON COMPANY**	36-0938600

(an Illinois corporation)

440 South LaSalle Street

Chicago, Illinois 60605-1028

(312) 394-4321

000-16844	**PECO ENERGY COMPANY**	23-0970240

(a Pennsylvania corporation)

P.O. Box 8699

2301 Market Street

Philadelphia, Pennsylvania 19101-8699

(215) 841-4000

1-1910	**BALTIMORE GAS AND ELECTRIC COMPANY**	52-0280210

(a Maryland corporation)

2 Center Plaza

110 West Fayette Street

Baltimore, Maryland 21201-3708

(410) 234-5000

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:

Cumulative Preferred Stock, without par value: $4.68 Series, $4.40 Series, $4.30 Series and $3.80 Series	New York
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, 2012 was as follows:

Exelon Corporation Common Stock, without par value	$ 32,084,086,343
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, 2013 was as follows:

Exelon Corporation Common Stock, without par value	855,019,272
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,761
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 2013 Annual Meeting of

Shareholders and the Commonwealth Edison Company and PECO Energy Company 2013 information statements are incorporated by reference in Part III.

Exelon Generation Company, LLC 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.

TABLE OF CONTENTS

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
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
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO 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
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended

Other Terms and Abbreviations

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
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
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	Midwest Independent Transmission System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MRV	Market-Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
n.m.	not meaningful
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
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
SFC	Supplier Forward Contract
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 19 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 its principal subsidiary, Generation, in the energy generation business, and through its principal subsidiaries 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 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 21 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 Energy Group, Inc. 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 is one of the largest competitive electric generation companies in the United States, as measured by owned and contracted MW. Generation creates incremental strategic value by operating as an integrated business and matching its large generation fleet with a leading customer-facing platform. Generation s presence in well-developed energy markets, its integrated hedging strategy mitigating short-term market volatility, and its low-cost nuclear generating fleet operating consistently at high capacity factors, position it well to succeed in competitive energy markets.

Generation s customer-facing business, now referred to as Constellation, utilizes Generation s energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in spot markets. Generation also sells other energy-related products and other services to meet its customers requirements. Generation is dependent upon continued deregulation of retail electric and gas markets and its ability to generate and obtain supplies of electricity and gas at competitive prices in the market.

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. 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 exist in a number of regions to provide transmission service across multiple transmission systems. CAISO, PJM, MISO, ISO-NE, ISO-NY and SPP, have been approved by FERC as RTOs. 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, Generation acquired Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, which developed and will build, operate, and maintain the project. The first block began operations in December 2012, with three additional blocks coming online in February 2013 and an expectation of full commercial operation by the end of the third quarter of 2013. When fully operational, Antelope Valley will be one of the largest PV solar projects in the world, with approximately 3.8 million solar panels generating enough clean, renewable electricity to power the equivalent of 75,000 average homes per year. The project has a 25-year PPA, approved by the California Public Utilities Commission, with Pacific Gas & Electric Company for the full output of the plant. Exelon expects to invest up to $701 million in equity in the project through 2013. The DOE s Loan Programs Office issued a loan guarantee of up to $646 million to support project financing for Antelope Valley. Exelon expects the total investment of up to $1.3 billion to be accretive to earnings and cash flows beginning in 2013. Once constructed and operating, the project is expected to have stable earnings and cash flow profiles due to the PPA.

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.

Exelon Wind. In 2010, Generation acquired 735 MWs of installed, operating wind capacity located in eight states for approximately $893 million in cash. In addition, Generation acquired development stage projects which became fully operational in 2012.

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

Significant Dispositions

Maryland Clean Coal Stations. Associated with certain of the regulatory approvals required for the merger, Exelon and Constellation agreed to enter into contracts to sell three Constellation generating stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland within 150 days (subsequently extended 30 days by the DOJ)

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following the merger completion. In accordance with that agreement, on November 30, 2012, a subsidiary of Generation sold these three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC for estimated net proceeds from the sale 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, 2012, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets [a]	
Nuclear	17,202
Fossil	12,050
Renewable (including Hydroelectric) [b]	3,516
Owned generation assets	32,768
Long-term contracts [c]	9,296
Investment in CENG [d]	1,963
Total generating resources	44,027

(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 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 22 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 32% of capacity). Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee; and the entire United States footprint of MISO, 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 the 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 11% of capacity). Other Regions is an aggregate of regions not considered individually significant (approximately 12% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,202 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). 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 2012 and 2011, electric supply (in GWh) generated from

the nuclear generating facilities was 53% and 82%, 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 3,925 MW. See ITEM 2. PROPERTIES for additional information on these sites.

Generation has a unit contingent PPA with CENG under which it purchases 85 to 90% of the output of CENG s nuclear generating facilities that is not sold to third parties under the pre-existing PPAs through 2014. Beginning on January 1, 2015, and continuing to the end of the lives of the respective nuclear facilities, Generation will purchase 50.01% and EDF will purchase 49.99% of the output of the CENG s nuclear facilities. All commitments to purchase subsequent to December 31, 2014 are at market prices. See Note 22 Related Party Transactions 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 2012 and 2011, the nuclear generating facilities operated by Generation achieved capacity factors of 92.7% and 93.3%, 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, 2012, the NRC categorized each unit operated by Generation in the Licensee Response Column, which is the highest of five performance bands. The NRC may modify, suspend or revoke operating licenses and impose civil penalties for failure to comply with the Atomic Energy Act, the regulations under such Act or the terms of the operating licenses. Changes in

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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. 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 on June 30, 2011, received 20-year operating license renewals for Salem Units 1 and 2. On December 8, 2010, in connection with an Administrative Consent Order (ACO) with the NJDEP, 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	1	1988	2026
	2	1988	2027
Byron	1	1985	2024
	2	1987	2026
Clinton	1	1987	2026
Dresden [b]	2	1970	2029
	3	1971	2031
LaSalle	1	1984	2022
	2	1984	2023
Limerick [c]	1	1986	2024
	2	1990	2029
Oyster Creek [b][d]	1	1969	2029
Peach Bottom [b]	2	1974	2033
	3	1974	2034
Quad Cities [b]	1	1973	2032
	2	1973	2032
Salem [b]	1	1977	2036
	2	1981	2040
Three Mile Island [b]	1	1974	2034

(a) Denotes year in which nuclear unit began commercial operations.
(b) Stations for which the NRC has issued a renewed operating licenses.
(c) On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years.
(d) 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. Using proven technologies, 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. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the plan in light of changing market conditions. Decisions to implement uprates at particular nuclear plants, the amount of expenditures to implement the plan, and the actual MWs of additional capacity attributable to the uprate program will be determined on a project-by-project basis in accordance with Exelon s normal project evaluation standards and ultimately will depend on market conditions, economic and policy considerations, and other factors.

Based on recent reviews, the nuclear uprate implementation plan was adjusted during 2012, primarily as a result of market conditions, including low natural gas prices and the continued sluggish economy, resulting in the deferral or cancellation of certain projects. In addition, the ability to implement several projects requires the successful resolution of various technical matters. The resolution of these matters may further affect the timing and amount of the power increases associated with the power uprate initiative. Following these reviews, any projects that may be undertaken are expected to be completed by the end of 2021, and may result in between 1,125 and 1,200 MWs of additional capacity at an overnight cost of approximately $3.4 billion in 2013 dollars. Overnight costs do not include financing costs or cost escalation.

Approximately 75% of the planned uprate MWs projects are either complete and in service or in the installation or design and engineering phases across seven nuclear stations including Limerick and Peach Bottom in Pennsylvania and Byron, Braidwood, Dresden, LaSalle and Quad Cities in Illinois. The remaining 25% of uprate MWs, if and when completed, would come from an extended power uprate project at Limerick currently scheduled to begin in 2017. From the program announcement in 2008 through December 31, 2012, Generation has placed in service 310 MWs of nuclear generation through the uprate program at a cost of approximately $810 million, which has been capitalized to property, plant and equipment on Exelon s and Generation s consolidated balance sheets. At December 31, 2012, an additional approximate $310 million has been capitalized to construction work in progress (CWIP) within property, plant and equipment on Exelon s and Generation s consolidated balance sheets, of which approximately $200 million (202 MWs) relates to projects currently in the installation phase. The remaining $110 million (346 MWs) in CWIP relates to projects currently in the design and engineering phase that continue to be evaluated in accordance with Exelon s normal project evaluation standards. The completion of those projects in the design and engineering phase will ultimately depend on market conditions, economic and policy considerations, and other factors. As of December 31, 2012, Generation believes it is more likely than not that all projects in CWIP will ultimately be placed in service. If a project in the design and engineering phase is expected to not be completed as planned, previously capitalized costs would be reversed through earnings as a charge to operating and maintenance expense.

New Nuclear Site Development. On August 28, 2012, Exelon halted efforts to gain initial federal regulatory approvals for new nuclear construction in Victoria County, Texas and notified the Nuclear Regulatory Commission that it has withdrawn its related Early Site Permit application. The action is in response to low natural gas prices and economic and market conditions that have made construction

of new merchant nuclear power plants in competitive markets uneconomical now and for the foreseeable future. The withdrawal of the license application brings an end to all project activity.

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, 2012, Generation had approximately 58,100 SNF assemblies (13,900 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 13 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 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 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 19 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 federally 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 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. 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 a major accidental outage at any of its nuclear stations. Generation has reduced its financial exposure to these risks through insurance and other industry risk-sharing provisions. See Nuclear Insurance within Note 19 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, 9 and 13 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 liability to decommission Dresden Unit 1 and Peach Bottom Unit 1 as of December 31, 2012 was $195 million and $121 million, respectively. As of December 31, 2012, NDT funds set aside to pay for these obligations were $390 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 has 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 associated with Zion Station. Pursuant to the ASA, ZionSolutions can 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 13 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 15,566 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. 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 2012 and 2011, electric supply (in GWh) generated from owned fossil and renewable generating facilities was 12% and 7%, 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.

Exelon Wind. During 2012, six development projects with a combined capacity of approximately 400 MWs began commercial operations. See ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS Exelon Corporation, Executive Overview for additional information.

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. The FERC review process is scheduled to be completed by August 31, 2014 and September 1, 2014, when the current Conowingo and Muddy Run licenses expire.

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 Contracts

In addition to energy produced by owned generation assets, Generation sells electricity purchased 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, 2012:

Region	Number of Agreements	Expiration Dates	Capacity (MW)
Mid-Atlantic [(a)]	13	2013 - 2032	973
Midwest	10	2013 - 2026	2,981
New England	6	2015 - 2020	637
New York [(a)]	1	2013	100
ERCOT	3	2013 - 2022	1,088
Other Regions	10	2015 - 2030	3,517
Total	43		9,296

	2013	2014	2015	2016	2017
Capacity Expiring (MW)	1,369	55	1,730	4	2,083

(a) Excludes contracts with CENG.

Fuel

The following table shows sources of electric supply in GWh for 2012 and 2011:

	Source of Electric Supply [a]	
	2012	**2011**
Nuclear	139,862	139,297
Purchases non-trading portfolio[b]	91,994	18,908
Fossil	27,760	7,385
Renewable	4,079	4,253
Total supply	263,695	169,843

(a) Represents Generation s proportionate share of the output of its generating plants.
(b) Includes purchases in 2012 pursuant to Generation s PPA with CENG. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

The fuel costs for nuclear generation are less than 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 2017. 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, and 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. Coal is procured primarily through annual supply contracts, with the remainder supplied through either short-term or spot-market purchases.

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 10 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 beyond 2013 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, 2012, the percentage of expected generation hedged for the major reportable segments was 94%-97%, 62%-65% and 27%-30% for 2013, 2014, and 2015, 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, 2012, 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:

	Net Capacity Purchases [a]	Power-Related Purchases [b]	Transmission Rights Purchases [c]	Purchased Energy from CENG	Total
2013	$ 374	$ 95	$ 28	$ 777	$ 1,274
2014	353	69	26	516	964
2015	350	25	13		388
2016	266	11	2		279
2017	203	3	2		208
Thereafter	469	5	34		508
Total	$ 2,015	$ 208	$ 105	$ 1,293	$ 3,621

(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, 2012, 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 capacity charges which are contingent on plant availability.

(b) Power-Related Purchases include firm REC purchase agreements. 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, 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 available output of CENG s nuclear plants at market prices. 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 22 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 2013 are as follows:

(in millions)	
Nuclear fuel [a]	$ 1,000
Production plant	1,000
Renewable energy projects [b]	575
Uprates	225
Other	50
Total	$ 2,850

(a) Includes Generation s share of the investment in nuclear fuel for the co-owned Salem plant.
(b) Primarily relates to expenditures for the completion of the Antelope Valley development project.

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 2013 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 15, 2009, and was 16,328 MWs.

Retail Electric Services

Under Illinois law, transmission and distribution services are regulated, while electric customers are allowed to purchase electricity supply from a competitive retail electric supplier.

Electric revenues and purchased power expense are affected by fluctuations in customers purchases from competitive retail electric suppliers. All ComEd customers have the ability to purchase energy from an alternative retail electric supplier. The customer 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 directly through to default service customers without markup 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 alternative 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 or cannot choose a

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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. On March 26, 2012, ComEd filed a notice of appeal. ComEd has recognized for accounting purposes its best estimate of any refund obligation.

On May 24, 2011, the ICC issued an order in ComEd s 2010 electric distribution 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. ComEd cannot predict the results of these appeals. 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. In order to fulfill a requirement of the Illinois Settlement Legislation, ComEd hedged the price of a significant portion of energy purchased in the spot market with a five-year variable-to-fixed financial swap contract with Generation that expires on May 31, 2013. 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 19 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 19 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information.

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 2013 is $1,400 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 497,000 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 December 20, 2004 and was 6,838 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 17, 2000 and was 718 mmcf.

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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 EGSs for the supply of retail electricity while retail transmission and distribution service remains regulated under the Competition Act. At December 31, 2012, there were 77 alternative EGSs serving PECO customers. At December 31, 2012, the number of retail customers purchasing energy from an alternative EGS was 496,500 representing approximately 31% of total retail customers. Retail deliveries purchased from EGSs represented approximately 66% of PECO s retail kWh sales for the year ended December 31, 2012. Customers that choose an alternative EGS 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 alternative EGSs.

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 an alternative EGS, PECO acts as the billing agent but does not record revenues or purchase power and fuel 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 has 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 include 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 current DSP Program, which expires 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 will purchase electric supply for default service customers from June 1, 2013 through May 31, 2015. Pursuant to the second DSP Program, PECO will procure 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 beginning in June 2013.

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 EGSs beginning April 1, 2014. PECO expects to file its plan for CAP customers by May 1, 2013.

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. 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 approved four-year Phase I EE&C plan totals approximately $328 million and sets forth how PECO will meet the required reduction targets established by Act 129 s EE&C provisions. PECO s plan includes a CFL program, weatherization programs, an energy efficiency 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. Under Act 129 s EE&C provisions, PECO was required to reduce peak demand by a minimum of 4.5% of its 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 will report its compliance with the reduction targets in a preliminary filing with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by November 15, 2013. In addition, PECO is required to reduce electric consumption in its service territory by 3% through May 31, 2013.

On August 2, 2012, the PAPUC issued its Phase II EE&C implementation order, under which the PAPUC has established PECO s three year cumulative consumption reduction target at 2.9%. PECO filed its three year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan sets forth how PECO will reduce electric consumption by at least 2.9% 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, 2012, the number of retail customers purchasing natural gas from a competitive natural gas supplier was 53,600, representing approximately 11% of total retail customers. Retail deliveries purchased from competitive natural gas suppliers represented approximately 16% of PECO s mmcf sales for the year ended December 31, 2012. PECO provides distribution, billing, metering, installation, maintenance and emergency response services at regulated rates to all its customers in its service territory.

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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 two years in accordance with its annual PAPUC PGC settlement. PECO s aggregate annual firm supply under these firm transportation contracts is 35 million dekatherms. Peak natural gas is provided by PECO s liquefied natural gas (LNG) facility and propane-air plant. PECO also has under contract 23 million dekatherms of underground storage through service agreements. Natural gas from underground storage represents approximately 30% of PECO s 2012-2013 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 2013 is $569 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 810 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 grants 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.

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BGE s highest peak load occurred on July 21, 2011 and was 7,236 MW; its highest peak load during winter months occurred on February 6, 2007 and was 6,347 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 impacted 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 their EGS. 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 no impact on electric revenue net of purchased power expense or BGE s financial position. At December 31, 2012, there were 53 alternative EGSs serving BGE customers. At December 31, 2012, the number of retail customers purchasing energy from an alternative EGS was 362,117, representing approximately 29% of total retail customers. Retail deliveries purchased from EGSs represented approximately 60% of BGE s retail kWh sales for the year ended December 31, 2012.

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 a combined application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October 22, 2012, BGE filed an updated application to request an increase of $131 million to its electric distribution base revenue requirement. The new electric distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

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 significantly reduce the rate impact of those investments on BGE customers. In total, through the ten year life of the Smart Grid program, BGE plans to spend up to $835 million on its smart grid and smart meter infrastructure.

Energy Efficiency Programs. BGE s energy efficiency programs include a CFL program, weatherization programs, an energy efficiency 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 no impact on gas revenue net of purchased power expense or BGE s financial position. At December 31, 2012, there were 27 alternative NGSs serving BGE customers. At December 31, 2012, the number of retail customers purchasing fuel from an alternative NGS was 143,351, representing approximately 22% of total retail customers. Retail deliveries purchased from NGSs represented approximately 56% of BGE s retail mmcf sales for the year ended December 31, 2012.

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 1,000 mmcf and a daily capacity of 298 mmcf,

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a liquefied natural gas facility for natural gas system pressure support with a total storage capacity of 5.8 mmcf and a daily capacity of 5.8 mmcf, and

a propane air facility and a mined cavern with a total storage capacity equivalent to 500 mmcf and a daily capacity of 81 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 a combined application for increases to its electric and gas base rates with the MDPSC. The requested rate of return on equity in the application is 10.5%. On October 22, 2012, BGE filed an updated application to request an increase of $45 million to its gas distribution base revenue requirement. The new gas distribution base rates are expected to take effect in late February 2013. BGE cannot predict how much of the requested increases, if any, the MDPSC will approve.

Construction Budget

BGE 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. 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 2013 is $663 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, 2012, Exelon and its subsidiaries had 26,057 employees in the following companies, of which 8,665 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	1,701	110	1,889	3,700	12,116
ComEd	3,571			3,571	5,902
PECO		1,286		1,286	2,453
BGE					3,360
Other [(d)]	82		26	108	2,226
Total	5,354	1,396	1,915	8,665	26,057

(a)

A separate CBA between ComEd and IBEW Local 15, ratified on October 10, 2012, covers approximately 24 employees in ComEd s System Services Group. Generation s and ComEd s separate CBAs with IBEW Local 15 will expire in 2013.

(b) 1,286 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 March 31, 2015 and covers 110 employees.

(c) 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 2009 and 2010, Generation entered into CBAs with the Security Officer unions at Oyster Creek and Limerick, which expire in 2013 and 2014, respectively. Additionally, during 2009, a 5-year agreement was reached with Oyster Creek Nuclear Local 1289, which will expire in 2015. In 2010, a 3-year agreement was negotiated with New England ENEH, UWUA Local 369, which will expire in 2014 and covers 10 employees.

(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 U.S. Congress and by 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, but not limited to, 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, and to its energy delivery oversight committee authority to 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 substantially reduce 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 19 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.

During 2012, one of Generation s co-owned facilities began a project to install environmental control equipment. Total costs incurred as of December 31, 2012 was approximately $39 million. The amount to be expended at Exelon and Generation in 2013, 2014 and 2015 is expected to total $70 million, $45 million and $5 million, respectively.

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 19 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, the 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 19 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 2013 at Exelon for compliance with environmental remediation related to contamination at former MGP sites is expected to total $57 million, consisting of $51 million, $6 million and $0 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, 2012, 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 19 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 National Academy of Sciences in May 2011. 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 2012, 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 most recent meeting of the United Nations Framework on Climate Change Conference of the Parties (COP 18) in December 2012. 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. The new global agreement has been agreed to in concept and further development of its GHG emissions reductions is scheduled to begin in 2015. At this point, there is much debate about the different levels of emission reductions that will be required for developed and developing countries. Another significant outcome of the COP 18 was a re-examination of the long-term temperature goal which could influence international climate policy by the United Nations.

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.

The U.S. EPA is addressing the issue of carbon dioxide (CO_2) emissions regulation for new and existing electric generating units through the Section 111 NSPS under the existing provisions of the Clean Air Act. A proposed Section 111(b) regulation for new units is to be finalized in spring 2013, and may result in material costs of compliance for CO_2 emissions for new fossil-fuel electric generating units. The U.S. EPA is also expected to propose a Section 111(d) rule in 2013 to establish CO_2 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 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 CO_2 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 CO_2 allowances available for purchase at auction. (CCR rigger 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, 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 directs the MDE to work with other state agencies to prepare an implementation plan to meet this goal. An interim plan was submitted to the Governor and the General Assembly during the 2012 legislative session, and the final GGRA plan is expected in February of 2013. The final GGRA plan is not expected to impose any additional requirements on BGE. Maryland targeted electricity consumption reduction goals required under the Empower Maryland program, and mandatory State participation in the Regional Greenhouse Gas Reduction Initiative (RGGI) Program will be listed as that sector s contribution in the GGRA plan.

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 are the energy efficiency and renewable portfolio standards in the Illinois Power Act that apply to ComEd.

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.

Efforts to achieve the Exelon 2020 goal will be supported by the company s current business plans as well as future initiatives that will be integrated into the annual business planning process. This includes a periodic review and refinement of Exelon 2020 initiatives in light of changing market conditions, regulations, technology and other factors that affect the merit of various GHG abatement options. Specific initiatives and the amount of expenditures to implement the plan will depend on economic and policy developments, and will be made on a project-by-project basis in accordance with Exelon s normal project evaluation standards.

Renewable and Alternative Energy Portfolio Standards

Twenty-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, 2012, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 3 and Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.

The AEPS Act was effective for PECO on January 1, 2011, following the expiration of PECO s transition period. During 2012, PECO was required to supply approximately 4.0% and 6.2% 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) and 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 0.0% from Tier 2 sources. In 2012, 6.5% were required from Tier 1 renewable sources, including at least 0.1% 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 19 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 21, 2013

Exelon

Name	Age	Position	Period
Crane, Christopher M.	54	Chief Executive Officer, Exelon;	2012 - Present
		Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon; President, Generation	2008 - Present
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
		Executive Vice President, Exelon	2007 - 2008
Shattuck III, Mayo A.	58	Executive Chairman, Exelon	2012 - Present
		Chairman, President and Chief Executive Officer, Constellation	2001 - 2012
Cornew, Kenneth W.	47	Executive Vice President and Chief Commercial Officer, Exelon;	2012 - Present
		President and Chief Executive Officer, Constellation	2012 - Present
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
		Senior Vice President, Trading and Origination, Power Team	2007 - 2008
O Brien, Denis P.	52	Senior Executive Vice President, Exelon; Chief Executive Officer, Exelon Utilities	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.	54	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.	60	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
DeFontes Jr., Kenneth W.	62	President and Chief Executive Officer, BGE	2004 - Present
		Senior Vice President, Constellation Energy	2004 - 2012
Gillis, Ruth Ann M.	58	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
		Senior Vice President, Exelon	2002 - 2008
Von Hoene Jr., William A.	59	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
		Senior Vice President, Exelon	2006 - 2008
Thayer, Jonathan W.	41	Executive Vice President and Chief Financial Officer, Exelon	2012 - Present
		Senior Vice President and Chief Financial Officer, Constellation Energy; Treasurer, Constellation Energy	2008 - 2012
		Vice President, Constellation Energy	2004 - 2008
Glace, Joseph R.	52	Senior Vice President, Exelon	2012 - Present
		Chief Risk Officer, Exelon	2008 - Present
		Vice President, Exelon	2008 - 2012
DesParte, Duane M.	50	Vice President and Corporate Controller, Exelon	2008 - Present
		Vice President, Finance, Exelon Business Services Company	2007 - 2008

Generation

Name	Age	Position	Period
Crane, Christopher M.	54	Chief Executive Officer, Exelon; Chairman, ComEd, PECO & BGE	2012 - Present
		President, Exelon; President, Generation	2008 - Present
		Chief Operating Officer, Exelon	2008 - 2012
		Chief Operating Officer, Generation	2007 - 2010
		Executive Vice President, Exelon	2007 - 2008
Cornew, Kenneth W.	47	Executive Vice President and Chief Commercial Officer, Exelon; President and Chief Executive Officer, Constellation	2012 - Present
		Senior Vice President, Exelon; President, Power Team	2008 - 2012
		Senior Vice President, Trading and Origination, Power Team	2007 - 2008

Name	Age	Position	Period
Pacilio, Michael J.	52	President, Exelon Nuclear; Senior Vice President and Chief Nuclear Officer, Generation	2010 - Present
		Chief Operating Officer, Exelon Nuclear	2007 - 2010
DeGregorio, Ronald	50	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.	46	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
		Vice President and Controller, Constellation Energy Resources	2007 - 2008
Aiken, Robert	46	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.	54	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.	52	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.	43	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
Jensen, Val	57	Senior Vice President, Customer Operations, ComEd	2012 - Present
		Vice President, Marketing and Environmental Programs, ComEd	2008 - 2012
		Senior Vice President, ICF International	2006 - 2008

Name	Age	Position	Period
O Neill, Thomas S.	50	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	51	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.	51	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
		Vice President, Work Management and New Business	2007 - 2008
Anthony, J. Tyler	48	Senior Vice President, Distribution Operations, ComEd	2010 - Present
		Vice President, Transmission and Substations, ComEd	2007 - 2010
Waden, Kevin J.	41	Vice President, Comptroller, Accountant and Controller, ComEd	2009 - Present
		Director of Accounting Operations, ComEd	2007 - 2009

PECO

Name	Age	Position	Period
Adams, Craig L.	60	President and Chief Executive Officer, PECO	2012 - Present
		Senior Vice President and Chief Operating Officer, PECO	2007 - 2012
Barnett, Phillip S.	49	Senior Vice President and Chief Financial Officer, PECO	2007 - Present
		Treasurer, PECO	2012 - Present
Innocenzo, Michael A.	47	Senior Vice President, Operations, PECO	2012 - Present
		Vice President, Distribution System Operations and Smart Grid/Smart Meter, PECO	2010 - 2012
		Vice President, Distribution System Operations	2007 - 2010
Webster Jr., Richard G.	51	Vice President, Regulatory Policy and Strategy, PECO	2012 - Present
		Director of Rates and Regulatory Affairs	2007 - 2012
Murphy, Elizabeth A.	53	Vice President, Governmental and External Affairs, PECO	2012 - Present
		Director, Governmental & External Affairs, PECO	2007 - 2012
Alden, Mark F.	52	Vice President, Customer Operations, PECO	2009 - Present
		Vice President Gas, PECO	2007 - 2009

Name	Age	Position	Period
Diaz Jr., Romulo L.	66	Vice President and General Counsel, PECO	2012 - Present
		Vice President, Governmental and External Affairs, PECO	2009 - 2012
		Associate General Counsel, Exelon	2008 - 2009
		City Solicitor, City of Philadelphia	2005 - 2008
Bailey, Scott A.	36	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.	62	President and Chief Executive Officer, BGE	2004 - Present
		Senior Vice President, Constellation Energy	2004 - 2012
Woerner, Stephen J.	45	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	Vice President, Chief Financial Officer and Treasurer, BGE	2011 - Present
		Executive Director, Investor Relations, Constellation Energy	2009 - 2011
		Director, Corporate Strategy and Development, Constellation Energy	2008 - 2009
Case, Mark D.	51	Vice President, Strategy and Regulatory Affairs, BGE	2012 - Present
		Senior Vice President, Strategy and Regulatory Affairs, BGE	2007 - 2012
Dempsey, Mary E.	57	Vice President, Governmental Affairs, BGE	2012 - Present
		Executive Director, State Affairs, Constellation Energy	2010 - 2012
		Managing Director, Public Affairs, Constellation Energy	2008 - 2009
Mills, Jeannette M.	46	Vice President, Customer Operations, BGE	2012 - Present
		Chief Customer Officer, BGE	2011 - Present
		Senior Vice President, Customer Relations and Account Services, BGE	2008 - 2012
		Senior Vice President, Gas Operations and Planning, BGE	2007 - 2008
Gahagan, Daniel P.	59	Vice President and General Counsel, BGE	2007 - Present
Vahos, David M.	40	Vice President and Controller, BGE	2012 - Present
		Executive Director, Audit, Constellation	2010 - 2012
		Director, Finance, BGE	2006 - 2010

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 risk oversight and audit committees of the Exelon Board of directors and the ComEd, PECO and BGE Boards of Directors. In addition, the Exelon Board of directors generation oversight and energy delivery oversight committees, respectively, evaluate risks related to the generation and energy delivery businesses. 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, 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 wholesale and retail power markets. Wholesale power prices are a function of supply and demand, which in turn are driven by factors such as the price of fuels, in particular the price of natural gas and coal, that drive the wholesale market prices that Generation s nuclear power plants receive, the rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation s output is sold, and the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs. In addition, the load serving and retail marketing activities compete for customers in a competitive environment which impacts the margins that Generation can earn and the volumes that it is able to serve.

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. As a result of the merger with Constellation that closed on March 12, 2012, Exelon is subject to additional risks.

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

Market and Financial Risks

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

Generation hedges the price risk associated with the generation it owns, or controls, through long-term power purchase agreements. Absent any hedging activity through fixed price transactions, Generation would be exposed to the risk of rising and falling spot market prices in the markets in which its assets are located, which would mean that Generation s cash flows would vary accordingly.

The wholesale 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. Many times, the next unit of electricity will be supplied from generating stations fueled by fossil fuels, and, therefore, the market price of power will reflect the market price of the marginal fuel. Consequently, changes in the market price of fossil fuels will cause 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 further downward pressure on natural gas prices and has reduced Generation s revenues. In addition, further delay or elimination of EPA air quality regulations could prolong the duration for which the cost of pollution is not factored into market prices which could reduce Generation s revenue. Further, in the event that alternative generation resources, such as wind and solar, are mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation and added to the available generation supply such resources could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region, including Generation, would be able to sell their output. These events could adversely affect Generation s financial condition, results of operations, and cash flows, and could also result in an impairment of certain long-lived assets.

The market price for electricity is also affected by changes in the demand for electricity. Worse than expected economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can depress demand. The result is that higher-cost generating resources do not run as frequently, putting downward pressure on market prices for electricity. The continued sluggish economy in the United States has in fact led to a slowdown in the growth of demand for electricity. If this continues, it could adversely affect the Registrants abil