Exelon

2012 Annual Report

Exelon Corporate 2012 Annual Report

CORPORATE PROFILE

Exelon Corporation is the nation's leading competitive energy provider, with 2012 revenues of approximately $23.5 billion. Headquartered in Chicago, Exelon has operations and business activities in 47 states, the District of Columbia and Canada. Exelon is one of the largest competitive U.S. power generators, with approximately 35,000 megawatts of owned capacity comprising one of the nation's cleanest and lowest-cost power generation fleets. The company's Constellation business unit provides energy products and services to approximately 100,000 business and public sector customers and more than 1 million residential customers. Exelon's utilities deliver electricity and natural gas to more than 6.6 million customers in central Maryland (BGE), northern Illinois (ComEd) and southeastern Pennsylvania (PECO). Exelon is headquartered in Chicago and trades on the NYSE under the ticker EXC.

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Stock Ticker
EXC

Shareholder Inquiries
Exelon Corporation has appointed Wells Fargo Shareowner Services as its transfer agent, stock registrar, dividend disbursing agent and dividend reinvestment agent. Should you have questions concerning your registered shareholder account or the payment or reinvestment of your dividends, or if you wish to make a stock transaction or stock transfer, you may call shareowner services at Wells Fargo at the toll-free number shown to the left or access its website at www.shareowneronline.com.

Morgan Stanley Smith Barney administers the Employee Stock Purchase Plan (ESPP) and employee stock options. Should you have any questions concerning your employee plan shares or wish to make a transaction, you may call the toll-free numbers shown to the left or access its website at www.benefitaccess.com.

The company had approximately 134,000 holders of record of its common stock as of Dec. 31, 2012.

The 2012 Form 10-K Annual Report to the Securities and Exchange Commission was filed on Feb. 21, 2012. To obtain a copy without charge, write to Bruce G. Wilson, Senior Vice President, Deputy General Counsel and Corporate Secretary, Exelon Corporation, Post Office Box 805379, Chicago, Illinois 60680-5379.

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BGE	Baltimore Gas and Electric Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, LLC
BondCo	RSB BondCo LLC
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
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

Other Terms and Abbreviations

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
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
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

Other Terms and Abbreviations

NEIL	Nuclear Electric Insurance Limited
NERC	North American Electric Reliability Corporation
NGS	Natural Gas Supplier
NJDEP	New Jersey Department of Environmental Protection
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
RFP	Request for Proposal
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)
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

The information included within this Annual Report has been taken from Exelon's Form 10-K annual report for the year ended December 31, 2012. That annual report was filed with the SEC on February 21, 2013 and can be viewed and retrieved through the SEC's website at *www.sec.gov* or our website at *www.exeloncorp.com*. We encourage you to consider the entire Form 10-K annual report, which contains more information about us and our subsidiaries than is presented in this Annual Report.

FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this Annual 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 Exelon include those factors discussed herein or in Exelon's 2012 Form 10-K, including those discussed in (a) Risk Factors, (b) Management's Discussion and Analysis of Financial Condition and Results of Operation, (c) Financial Statements and Supplementary Data: Note 19 and (d) other factors discussed in filings with the SEC by Exelon. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Annual Report. Exelon does not undertake any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Annual Report.

WHERE TO FIND MORE INFORMATION

Exelon's 2012 Form 10-K is available on Exelon's website at *www.exeloncorp.com* and will be made available, without charge, in print to any shareholder who requests such documents from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680-5398.

GENERAL DESCRIPTION OF OUR BUSINESS

General

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) 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 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 of Exelon's 2012 Form 10-K 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 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 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 of Exelon's 2012 Form 10-K. 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 Management's Discussion and Analysis of Financial Condition and Results of Operations—Exelon Corporation, Executive Overview; 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 of Exelon's 2012 Form 10-K.

Exelon Wind. During 2012, six development projects with a combined capacity of approximately 400 MWs began commercial operations. See 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 of Exelon's 2012 Form 10-K.

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 of Exelon's 2012 Form 10-K, 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 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 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 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 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.

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.

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. 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,
- 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.

Environmental Regulation

General

Exelon is 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. Exelon is 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.

Exelon and its 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, Exelon 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.

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

MARKET FOR OUR COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2013, there were 855,019,272 shares of common stock outstanding and approximately 134,194 record holders of common stock.

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

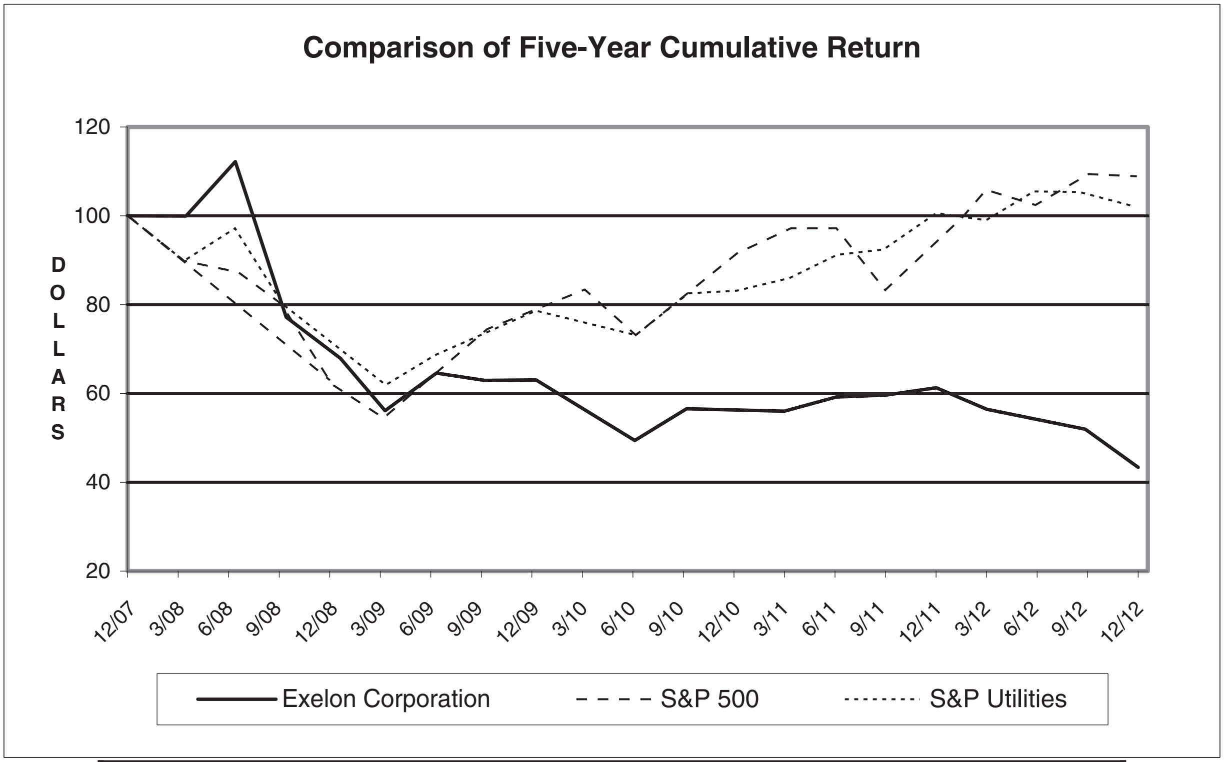
	2012				2011			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$37.50	$39.82	$39.37	$43.70	$45.45	$45.27	$42.89	$43.58
Low price	28.40	34.54	36.27	38.31	39.93	39.51	39.53	39.06
Close	29.74	35.58	37.62	39.21	43.37	42.61	42.84	41.24
Dividends	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525

Stock Performance Graph

The performance graph below illustrates a five-year comparison of cumulative total returns based on an initial investment of $100 in Exelon common stock, as compared with the S&P 500 Stock Index and the S&P Utility Index for the period 2008 through 2012.

This performance chart assumes:

- $100 invested on December 31, 2007 in Exelon common stock, in the S&P 500 Stock Index and in the S&P Utility Index; and
- All dividends are reinvested.



	Value of Investment at December 31,					
	2007	2008	2009	2010	2011	2012
Exelon Corporation	$100.00	$70.14	$64.25	$57.54	$62.96	$45.74
S&P 500	$100.00	$63.00	$79.68	$91.68	$93.61	$108.59
S&P Utilities	$100.00	$71.02	$79.48	$83.82	$100.54	$101.86

Dividends

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

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

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

PECO's Amended and Restated Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2012, such capital was $3 billion and amounted to about 34 times the liquidating value of the outstanding preferred securities of $87 million.

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

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

At December 31, 2012, Exelon had retained earnings of $9,893 million, including Generation's undistributed earnings of $3,168 million, ComEd's retained earnings of $721 million consisting of retained earnings appropriated for future dividends of $2,360 million, partially offset by $1,639 million of unappropriated retained deficits, PECO's retained earnings of $593 million, and BGE's retained earnings of $808 million.

The following table sets forth Exelon's quarterly cash dividends per share paid during 2012 and 2011:

	2012				2011			
(per share)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Exelon	$0.525	$0.525	$0.525	$0.525	$0.525	$0.525	$0.525	$0.525

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

	2012				2011			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$242	$493	$291	$600	$111	$ 61	$—	$—
ComEd	10	10	10	75	75	75	75	75
PECO	85	86	85	87	80	84	73	111
BGE	—	—	—	—	—	—	—	85 (a)

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

First Quarter 2013 Dividend. On February 6, 2013, the Exelon Board of Directors declared a first quarter 2013 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 8, 2013, to shareholders of record of Exelon at the end of the day on February 19, 2013.

Revised Dividend Policy. On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Board of Directors. The second quarter 2013 quarterly dividend of $0.31 per share on Exelon's common stock is expected to be approved by the Exelon Board of Directors in the second quarter of 2013.

SELECTED FINANCIAL DATA

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

	For the Years Ended December 31,				
(In millions, except per share data)	2012 [(a)]	2011	2010	2009	2008
Statement of Operations data:					
Operating revenues	$23,489	$19,063	$18,644	$17,318	$18,859
Operating income	2,380	4,479	4,726	4,750	5,299
Income from continuing operations	1,171	2,499	2,563	2,706	2,717
Income from discontinued operations	—	—	—	1	20
Net income	1,171	2,499	2,563	2,707	2,737
Earnings per average common share (diluted):					
Income from continuing operations	$ 1.42	$ 3.75	$ 3.87	$ 4.09	$ 4.10
Income from discontinued operations	—	—	—	—	0.03
Net income	$ 1.42	$ 3.75	$ 3.87	$ 4.09	$ 4.13
Dividends per common share	$ 2.10	$ 2.10	$ 2.10	$ 2.10	$ 2.03
Average shares of common stock outstanding—diluted	819	665	663	662	662

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

	December 31,				
(In millions)	2012	2011	2010	2009	2008
Balance Sheet data:					
Current assets	$10,133	$ 5,713	$ 6,398	$ 5,441	$ 5,130
Property, plant and equipment, net	45,186	32,570	29,941	27,341	25,813
Noncurrent regulatory assets	6,497	4,518	4,140	4,872	5,940
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	14,113	9,569	9,136	8,901	8,038
Total assets	$78,554	$54,995	$52,240	$49,180	$47,546
Current liabilities	$ 7,784	$ 5,134	$ 4,240	$ 4,238	$ 3,811
Long-term debt, including long-term debt to financing trusts	18,346	12,189	12,004	11,385	12,592
Noncurrent regulatory liabilities	3,981	3,627	3,555	3,492	2,520
Other deferred credits and other liabilities	26,626	19,570	18,791	17,338	17,489
Preferred securities of subsidiary	87	87	87	87	87
Noncontrolling interest	106	3	3	—	—
BGE preference stock not subject to mandatory redemption	193	—	—	—	—
Shareholders' equity	21,431	14,385	13,560	12,640	11,047
Total liabilities and shareholders' equity	$78,554	$54,995	$52,240	$49,180	$47,546

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Executive Overview

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

- *Generation,* whose integrated business consists of owned, contracted and investments in electric generating facilities managed through customer supply of electric and natural gas products and services, including renewable energy products, risk management services and natural gas exploration and production activities.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.
- *PECO,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.
- *BGE,* whose business consists of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and other regions in Generation), ComEd, PECO and BGE. See Note 21 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

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

Financial Results. The following consolidated financial results reflect the results of Exelon for year ended December 31, 2012 compared to the same period in 2011. The 2012 financial results only include the operations of Constellation and BGE from the date of the merger with Constellation (the Merger), March 12, 2012, through December 31, 2012. All amounts presented below are before the impact of income taxes, except as noted.

	The Years Ended December 31,		Favorable (Unfavorable) Variance
	2012	2011	
Operating revenues	$23,489	$19,063	$ 4,426
Purchased power and fuel	10,157	7,267	(2,890)
Revenue net of purchased power and fuel [(a)]	13,332	11,796	1,536
Other operating expenses			
Operating and maintenance	7,961	5,184	(2,777)
Depreciation and amortization	1,881	1,347	(534)
Taxes other than income	1,019	785	(234)
Total other operating expenses	10,861	7,316	(3,545)
Equity in earnings of unconsolidated affiliates	(91)	(1)	(90)
Operating income	2,380	4,479	(2,099)
Other income and (deductions)			
Interest expense, net	(928)	(726)	(202)
Other, net	346	203	143
Total other income and (deductions)	(582)	(523)	(59)
Income (loss) before income taxes	1,798	3,956	(2,158)
Income taxes	627	1,457	830
Net income (loss)	1,171	2,499	(1,328)
Net (loss) income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	11	4	(7)
Net income (loss) on common stock	$ 1,160	$ 2,495	$(1,335)

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

Exelon's net income was $1,160 million for the year ended December 31, 2012 as compared to $2,495 million for the year ended December 31, 2011, and diluted earnings per average common share were $1.42 for the year ended December 31, 2012 as compared to $3.75 for the year ended December 31, 2011.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1,536 million primarily due to the addition of Constellation's and BGE's financial results. BGE's operating revenue net of purchased power and fuel expense was $1,039 million from March 12, 2012 to December 31, 2012, which included the $113 million impact of the residential customer rate credit in connection with the Merger. Generation's operating revenue net of purchased power and fuel expense increased by $518 million primarily due to the New England, New York, ERCOT and Other Regions. These regions contributed $729 million and did not previously have a significant impact on Generation's revenue net of purchased power and fuel expense prior to the Merger. Generation's results were also favorably affected by $588 million of other activities, including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities, and by $83 million in the Mid-Atlantic region also due to the addition of Constellation's operations in 2012. Generation had mark-to-market gains of $515 million in 2012 from economic hedging activities, net of intercompany eliminations, compared to $288 million in mark-to-market losses in 2011. Offsetting these favorable impacts, Generation incurred $1,098 million of amortization expense for the acquired energy contracts, net, recorded at fair value at the merger date. Also, revenue net of purchased power and fuel expenses decreased by $549 million in the Midwest region due to lower capacity revenues, increased nuclear fuel costs and lower realized power prices. ComEd's operating revenues net of purchased power and fuel expense increased by $115 million primarily as a result of the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, net of lower allowed return on equity, and increased transmission revenue. PECO's operating revenues net of purchased power and fuel expense decreased by $45 million primarily as a result of unfavorable weather and a decline in electric load.

Operating and maintenance expense increased by $2,777 million primarily due to the addition of BGE and Constellation. In addition, Exelon's results were unfavorably affected by the $272 million loss on the sale of three Maryland generating stations, of which $278 million was recorded to operating and maintenance expense. Including Constellation and BGE, labor, other benefits, contracting and materials increased by $1,393 million, pension and non-pension postretirement benefits expense increased by $199 million and Constellation merger and integration costs increased by $226 million. In addition, Exelon incurred $216 million in costs incurred as part of the Maryland order approving the Merger and costs of $195 million associated with a settlement with the FERC in March, 2012, and BGE incurred $71 million of storm costs.

Depreciation and amortization expense increased by $534 million primarily due to higher plant balances resulting from the addition of BGE's and Constellation's plant balances as well as ongoing capital expenditures across the operating companies.

Equity in losses of unconsolidated affiliates increased by $90 million primarily due to the amortization of the basis difference in CENG recorded at fair value at the merger date, partially offset by net income generated from Exelon's equity investment in CENG.

Interest expense increased by $202 million due to an increase in debt obligations as a result of the Merger and an increase in debt issued at Generation and BGE in 2012. Offsetting these unfavorable impacts, interest expense at ComEd and PECO decreased due to a lower outstanding debt during 2012 and lower interest rates on long-term debt.

Exelon's effective income tax rates for the years ended December 31, 2012 and 2011 were 34.9% and 36.8%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the years ended December 31, 2012 and 2011, including explanation of the non-GAAP measure revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Adjusted (non-GAAP) Operating Earnings

Exelon's adjusted (non-GAAP) operating earnings for the year ended December 31, 2012 were $2,330 million, or $2.85 per diluted share, compared with adjusted (non-GAAP) operating earnings of $2,763 million, or $4.16 per diluted share, for the same period in

2011. In addition to net income, Exelon evaluates its operating performance using the measure of adjusted (non-GAAP) operating earnings because management believes it represents earnings directly related to the ongoing operations of the business. Adjusted (non-GAAP) operating earnings exclude certain costs, expenses, gains and losses and other specified items. This information is intended to enhance an investor's overall understanding of year-to-year operating results and provide an indication of Exelon's baseline operating performance excluding items that are considered by management to be not directly related to the ongoing operations of the business. In addition, this information is among the primary indicators management uses as a basis for evaluating performance, allocating resources, setting incentive compensation targets and planning and forecasting of future periods. Adjusted (non-GAAP) operating earnings is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report.

The following table provides a reconciliation between net income as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the year ended December 31, 2012 as compared to 2011:

	December 31,			
	2012		2011	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income	$1,160	$ 1.42	$2,495	$ 3.75
Mark-to-Market Impact of Economic Hedging Activities (a)	(310)	(0.38)	174	0.27
Unrealized (Gains) Losses Related to NDT Fund Investments (b)	(56)	(0.07)	1	—
Plant Retirements and Divestitures (c)	236	0.29	33	0.05
Asset Retirement Obligation (d)	1	—	16	0.02
Constellation Merger and Integration Costs (e)	257	0.31	46	0.07
Other Acquisition Costs (f)	3	—	5	0.01
Wolf Hollow Acquisition (g)	—	—	(23)	(0.03)
Recovery of Costs Pursuant to ComEd Distribution Rate Case Order (h)	—	—	(17)	(0.03)
Non-Cash Remeasurement of Deferred Income Taxes (i)	(117)	(0.14)	33	0.05
Amortization of Commodity Contract Intangibles (j)	758	0.93	—	—
Amortization of the Fair Value of Certain Debt (k)	(9)	(0.01)	—	—
Maryland Commitments (l)	227	0.28	—	—
FERC Settlement (m)	172	0.21	—	—
Midwest Generation Bankruptcy Charges (n)	8	0.01	—	—
Adjusted (non-GAAP) Operating Earnings	$2,330	$ 2.85	$2,763	$ 4.16

(a) Reflects the impact of (gains) losses for the years ended December 31, 2012 and 2011, respectively, on Generation's economic hedging activities (net of taxes of $200 million and $114 million, respectively). See Note 10 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's hedging activities.

(b) Reflects the impact of unrealized (gains) losses for the years ended December 31, 2012 and 2011, respectively, on Generation's NDT fund investments for Non-Regulatory Agreement Units (net of taxes of $(132) million and $(3) million, respectively). See Note 13 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Primarily reflects the impact associated with the sale of three generating stations associated with certain of the regulatory approvals required for the merger for the year ended December 31, 2012 (net of taxes of $106 million). For December 31, 2012 and 2011, also reflects incremental accelerated depreciation associated with the retirement of certain fossil generating units and compensation for operating two of the units past their planned retirement date under a FERC-approved reliability-must-run rate schedule. See Note 15 of the Combined Notes to Consolidated Financial Statements and "Results of Operations—Generation" for additional detail related to the generating unit retirements.

(d) Reflects the income statement impact for the years ended December 31, 2012 and 2011 primarily related to the increase in Generation's decommissioning obligation for spent nuclear fuel at retired nuclear units (net of taxes of $4 million and $11 million, respectively). Also reflects the reduction in Generation's asset retirement obligation for certain retired fossil-fueled generating stations in 2012 (net of taxes of $(3) million) and the reduction in PECO's asset retirement obligation in 2011 (net of taxes of $(1) million). See Note 13 of the Combined Notes to Consolidated Financial Statements for additional information.

(e) Reflects certain costs incurred in the years ended December 31, 2012 and 2011 (net of taxes of $161 million and $31 million, respectively) associated with the Constellation merger including transaction costs, employee-related expenses (e.g. severance, retirement, relocation and retention bonuses) and integration initiatives. See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(f) Reflects certain costs incurred in the years ended December 31, 2012 and 2011 associated with various acquisitions (net of taxes of $2 million and $3 million, respectively). See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(g) Reflects a non-cash bargain purchase gain (negative goodwill) for the year ended December 31, 2011 in connection with the acquisition of Wolf Hollow, net of acquisition costs (net of taxes of $15 million). See Note 4 of the Combined Notes to the Consolidated Financial Statements for additional information.

(h) Reflects a one-time benefit in 2011 to recover previously incurred costs as a result of the May 2011 ICC rate order (net of taxes of $5 million). See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

(i) Reflects the non-cash impacts of the remeasurement of state deferred income taxes, primarily as a result of the merger in 2012 and as a result of revised estimates of state apportionments in 2011. See Note 12 of the Combined Notes to the Consolidated Financial Statements for additional information.
(j) Reflects the non-cash impact for the year ended December 31, 2012 (net of taxes of $491 million) of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger date. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.
(k) Represents the non-cash amortization of certain debt for the year ended December 31, 2012 (net of taxes of $6 million) recorded at fair value at the Constellation merger date expected to be retired in 2013. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information.
(l) Reflects costs incurred for the year ended December 31, 2012 associated with the Constellation merger (net of taxes of $101 million) as part of the Maryland order approving the merger transaction. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(m) Reflects costs incurred for the year ended December 31, 2012 (net of taxes of $23 million) as part of a settlement with the FERC to resolve a dispute related to Constellation's pre-merger hedging and risk management transactions. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.
(n) Reflects estimated liabilities for the year ended December 31, 2012 (net of taxes of $5 million) pursuant to the Midwest Generation bankruptcy, primarily related to lease payments under a coal rail car lease and estimated payments for asbestos-related personal injury claims.

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

For the year ended December 31, 2012, expense has been recognized for costs incurred to achieve the merger as follows:

	Pre-tax Expense
	Twelve Months Ended December 31, 2012
Merger and Integration Costs [a]:	
Transaction [b]	$ 58
Maryland Commitments	328
Employee-Related [c]	164
Other [d]	196
Total	$746

(a) Includes the operations of the acquired businesses from the date of the merger, March 12, 2012, through December 31, 2012.
(b) External, third-party costs paid to advisors, consultants, lawyers and other experts to assist in the due diligence and regulatory approval processes and in the closing of the transaction.
(c) Costs primarily for employee severance, pension and OPEB expense and retention bonuses. ComEd and BGE established regulatory assets of $21 million and $22 million, respectively; the majority of these costs are expected to be recovered over a five-year period. These costs are not included in the table above.
(d) Costs to integrate Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. ComEd established a regulatory asset of $15 million for certain other merger and integration costs, which are not included in the table above.

As of December 31, 2012, Exelon projects incurring total additional merger-related expenses in 2013 and 2014 of approximately $135 million.

In addition, pursuant to conditions set forth by the MDPSC in its approval of the merger transaction, Generation expects to incur capital expenditures of $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for its competitive energy businesses (expected to be completed in 1 to 2 years) and up to $625 million for development of 285-300 MW of new electric generation facilities in Maryland (expected to be completed over the next ten years). The accounting treatment for the construction costs of the new headquarters building in Baltimore may vary depending on the structure of the transaction.

Exelon's Strategy and Outlook for 2013 and Beyond

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

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

Generation is managed as an integrated business and is located in multiple geographic regions, with multiple supply sources and provides various energy commodities through multiple distribution channels. Generation's nuclear, fossil fuel, hydroelectric and renewables strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding its regional and technological footprint. Generation's customer-facing activities enhance its existing customer platform, expand the business across states and develop innovative products for its customers.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. Exelon seeks to leverage its scale and expertise across the utilities platform by standardization and sharing of best practices to achieve improved operational and financial results.

Exelon's financial priorities are to maintain investment grade credit metrics and to return value to Exelon's shareholders with a sustainable dividend throughout the energy commodity market cycle and through earnings growth from attractive investment opportunities.

In pursuing its strategies, Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the power markets. Power prices are a function of supply and demand, which in turn are driven by factors such as (1) the price of fuels, in particular, the prices of natural gas and coal, which drive the market prices that Generation's power plants can obtain for their output, (2) the rate of expansion of subsidized low carbon generation in the markets in which Generation's output is sold, (3) the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs, and (4) the impacts of increased competition in the retail channel.

Power Markets

Price of Fuels. The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Since the third quarter of 2011, forward natural gas prices for 2013 and 2014 have declined significantly; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

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

Various states have implemented or proposed legislation, regulations or other policies to subsidize generation which thereby would artificially depress wholesale energy and capacity prices. For example, on April 12, 2012, the MDPSC issued an order directing the Maryland electric utilities to enter into a 20-year contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW combined cycle gas turbine in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. The CfD mandates that utilities (including BGE) pay (or receive) the difference between CPV's contract price and the revenues it receives for capacity and energy from clearing the unit in the PJM capacity market.

Similarly, in January 2011, New Jersey passed legislation that provides guaranteed cost recovery through a CfD for the development of up to 2,000 MWs of new base load or mid-merit generation, so long as it clears in PJM's capacity market. Three generation developers were chosen for the New Jersey CfD, for which contracts were executed in 2011 by the state's utilities under protest. Similarly, in Illinois, legislation has been debated for over four years that passed in the Senate and is currently being considered in the House which would require consumers to subsidize the development of an Integrated Gasification Combined Cycle plant by purchasing its electricity through 30 year power purchase agreements at prices significantly above market prices. A new version was recently introduced in the current General Assembly but its prospects are unclear at this time.

Exelon and others filed a complaint in federal district court challenging the constitutionality and other aspects of the New Jersey legislation. Similarly, Exelon and others are also challenging the selection of the three generation developers in New Jersey state court proceedings and the MDPSC actions in Maryland state court.

As required under their CfDs, two of the New Jersey generator developers and one in Maryland offered and cleared in PJM's capacity market auction held in May 2012. Given the state-required customer subsidy provided under their respective CfDs, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in this auction and may continue to do so in future auctions to the detriment of Exelon's market driven position. PJM's capacity market rules include a Minimum Offer Pricing Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. However, Exelon does not believe that the existing MOPR worked effectively with respect to the abovementioned generator developers. Accordingly, Exelon worked with other market stakeholders, PJM and PJM's independent market monitor to develop a new MOPR that would more effectively preclude such artificial price suppression, and PJM, after extensive stakeholder consideration, filed its new MOPR seeking FERC approval in December, 2012. On February 5, 2013, the FERC issued a letter finding that PJM's new MOPR filing is deficient and requested PJM provide additional information on several aspects of PJM's MOPR proposal. PJM has 30 days to respond, and a FERC decision is expected within 60 days thereafter. See Note 3 of the Combined Notes to Consolidated Financial Statements for further details of PJM's MOPR.

A continuation of these state efforts, if successful and unabated by an effective MOPR, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position and could have a material effect on Exelon's financial results of operations, financial position and cash flows.

Energy Demand. The continued sluggish economy in the United States has led to a decline in demand for electricity. ComEd is projecting load volumes to remain essentially flat in 2013 compared to 2012, while PECO and BGE are projecting a decline of 0.5% and 2.0%, respectively, in 2013 compared to 2012. The projected declines at PECO and BGE are a result of energy efficiency initiatives, the additional day in 2012 for the leap year and weak economic conditions in their service territories. The demand for electricity has also declined due to significantly milder than normal weather in 2012 and 2011. In addition, energy efficiency and demand response programs will result in decreased demand for energy. See Note 3 of the Combined Notes to Consolidated Financial Statements for further discussion of energy efficiency and demand response programs.

Retail Competition. Generation's retail business competes for customers in a competitive environment which impacts the margins that Generation can earn and the volumes that it is able to serve. Recently, sustained low forward natural gas and power prices and low market volatility have caused retail competitors to aggressively pursue market share, and wholesale generators (including Generation) to use the retail channel to hedge generation output. These factors have negatively impacted overall gross margins and profitability in Generation's business.

Strategic Policy Alignment

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

Exelon's Board of Directors declared the first quarter 2013 dividend of $0.525 per share, and in response to low forward prices and weaker financial expectations, among other factors, Exelon's Board of Directors approved a revised dividend policy going forward. The first quarter dividend is payable on March 8, 2013 to shareholders of record on February 19, 2013. The first quarter dividend is based on Exelon's previous policy of $2.10 per share on an annualized basis, while the new dividend policy contemplates a regular $0.31 per share quarterly dividend beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis). Consistent with past practice, all future quarterly dividends will require approval by Exelon's Board of Directors.

If recent power price volatility and demand trends continue, they could adversely affect the Registrants' ability to fund other discretionary uses of cash such as growth projects and dividends. In addition, economic conditions may no longer support the continued operation of certain generating facilities, which could adversely affect Generation's results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Hedging Strategy

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2013 and 2014. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of December 31, 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. 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. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well.

Generation procures coal, oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position. ComEd, PECO and BGE mitigate exposure as a result of the regulatory mechanisms that allow them to recover procurement costs from retail customers.

New Growth Opportunities

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.

Generation Renewable Development. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in Antelope Valley, a 230-MW solar photovoltaic (PV) project under development in northern Los Angeles County, California, from First Solar, Inc., which developed and will build, operate, and maintain the project. The first portion of the project began operations in December 2012, with additional blocks to come online and an expectation of full commercial operation by the end of the third quarter of 2013. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020. The project has a 25-year PPA, approved by the CPUC, with Pacific Gas & Electric Company for the full output of the plant. Upon completion, the facility will add 230 MWs to Generation's renewable generation fleet. Total costs for the facility are expected to be approximately $1.3 billion. Total costs incurred through December 31, 2012 were $679 million. Additionally, Generation constructed and placed into service six wind facilities in 2012, resulting in approximately 400 MWs of additional renewable generation. Total costs for the facilities were approximately $700 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission Development Project. Exelon and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop an extra high-voltage transmission project from the western Ohio border through Indiana to the northern portion of Illinois. Referred to as the Reliability Interregional Transmission Extension (RITE) Line project, the project is expected to strengthen the high-voltage transmission system and improve overall system reliability. RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) have been formed as project companies to develop and own the project. RITELine Illinois will own the transmission assets located in Illinois and is owned 75% by ComEd and 25% by RITELine Transmission Development Company, LLC (RTD). RITELine Indiana will own the transmission assets located in Indiana and is owned by AEP (75%) and RTD (25%). Exelon Transmission Company, LLC and AEP each own 50% of RTD. The total cost of the RITE Line project is expected to be approximately $1.6 billion, with the Illinois portion of the line expected to cost approximately $1.2 billion. The ultimate cost of the line is dependent on a number of factors, including RTO requirements, state siting requirements, routing of the line, and equipment and commodity costs. Exelon and AEP are pursuing the project for inclusion in PJM's RTEP under yet-to-be finalized planning criteria. The current estimated in-service date is 2019.

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

Smart Meter and Smart Grid Initiatives.

ComEd's Smart Meter and Smart Grid Investments. On December 5, 2012, the ICC approved ComEd's revised AMI Deployment Plan which includes the planned installation of 4 million electric smart meters. ComEd plans to invest approximately $1.3 billion on smart meters and smart grid under EIMA, including $1.0 billion through the AMI Deployment Plan.

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

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

See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on the utility infrastructure projects.

Liquidity

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

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. Generation has a bilateral credit facility with aggregate maximum availability of $0.3 billion.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. This facility will solely be utilized by Generation to issue letters of credit. See Liquidity and Capital Resources for additional information.

Exposure to Worldwide Financial Markets. Exelon has exposure to worldwide financial markets. The ongoing European debt crisis has contributed to the instability in global credit markets. Further disruptions in the European markets could reduce or restrict the Registrants' ability to secure sufficient liquidity or secure liquidity at reasonable terms. As of December 31, 2012, approximately 31%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.3 billion in aggregate total commitments of which $6.5 billion was available as of December 31, 2012. There were no borrowings under the Registrants' credit facilities as of December 31, 2012. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

Exelon has exposure related to various uncertain tax positions which Exelon manages through planning and implementation of tax planning strategies. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Environmental Legislative and Regulatory Developments.

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

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

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

On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon has been granted permission by the Court to intervene in support of the rule. A decision by the Court is expected sometime in 2013. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

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

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

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act, including permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective January 2, 2011. On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil-fueled power plants greater than 25 MW that would require the plants to limit CO_2 emissions. Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case-by-case basis. The U.S. EPA is also expected to establish in 2013 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and it is not yet known what the nature and impact of the final regulations will be.

Exelon supports comprehensive climate change legislation or regulation, including a cap-and-trade program for GHG emissions, which balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions.

Water Quality. Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. On March 28, 2011, the U.S. EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by July 27, 2013. The proposed rule does not require closed cycle cooling (e.g., cooling towers) as the best technology available, and also provides some flexibility in the use of cost-benefit considerations and site-specific factors. The proposed rule affords the state permitting agency wide discretion to determine the best technology available, which, depending on the site characteristics, could include closed cycle cooling, advanced screen technology at the intake, or retention of the current technology.

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

Hazardous and Solid Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion residuals (CCR) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCR either as a hazardous or non-hazardous waste, under RCRA. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. The Generation plants that would be affected by the proposed rules are Keystone and Conemaugh in Pennsylvania which have on-site landfills that meet the requirements of Pennsylvania solid waste regulations for non-hazardous waste disposal. However, until the final rule is adopted, the impact on these facilities is unknown. The U.S. EPA has not announced a target date for finalization of the CCR rules.

See Note 19 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Other Regulatory and Legislative Actions

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

Generation believes its nuclear generating facilities do not have the same operating risks as the Fukushima Daiichi plant because they meet the NRC's requirement that specifies all plants must be able to withstand the most severe natural phenomena historically reported for each plant's surrounding area, with a significant margin for uncertainty. In addition, Generation's plants are not located in significant earthquake zones or in regions where tsunamis are a threat. Generation believes its nuclear generating facilities are able to shut down safely and keep the fuel cooled through multiple redundant systems specifically designed to maintain electric power when electricity is lost from the grid. Further, Generation's nuclear generating facilities also undergo frequent scenario drills to ensure the proper function of the redundant safety protocols.

Since the events in Japan took place, Generation has continued to work with regulators and nuclear industry organizations to understand the events in Japan and apply lessons learned. Early on, the nuclear industry took a number of specific steps to respond, including actions requested by the Institute of Nuclear Power Operations (INPO) to perform tests that verified Generation's emergency equipment is available and functional, conduct walk-downs on its procedures related to critical safety equipment, confirm event response procedures and readiness to protect the spent fuel pool, and verify current qualifications of operators and support staff needed to implement the procedures. Generation has been addressing additional actions requested by INPO for improving and maintaining core and spent fuel pool cooling during an extended loss of power for at least 24 hours.

In April 2011, the NRC named six senior managers and staff to its task force for examining the agency's regulatory requirements, programs, processes, and implementation in light of information from the Fukushima Daiichi site in Japan, following the March 11 earthquake and tsunami (Task Force). On July 12, 2011, the NRC Task Force issued a report of its review of the accident, including recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The Task Force's report did not recommend any changes to the existing nuclear licensing process in the United States or changes in the storage of spent nuclear fuel within the plant's spent nuclear fuel pools. During the fourth quarter of 2011, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule which was approved by the NRC subject to a number of conditions. The NRC staff confirmed the Task Force's conclusions that none of the findings arising from the Task Force review presented an imminent risk to public health and safety.

In March 2012, the NRC authorized its staff to issue three immediately effective orders to commercial reactor licensees operating in the United States for compliance no later than December 31, 2016. In summary, the orders require licensees: (1) to provide sufficient onsite portable equipment and resources to maintain or restore cooling capabilities for the containment, core, and spent fuel pool until offsite equipment is available and have offsite equipment and resources available to sustain cooling functions indefinitely; (2) to improve the venting systems with boiling water reactor Mark I or Mark II containments (or for the Mark II plants, install new systems) that help prevent or mitigate core damage in the event of a serious accident by making the systems accessible and operable in the event of a prolonged station blackout and inadequate cooling; and (3) to install instrumentation to provide a reliable indication of water level in the spent fuel pool.

Additionally, the NRC has issued a detailed information request to every operating commercial nuclear power plant in the United States. The information requested requires: (1) use of the current NRC guidance to reevaluate current seismic and flood risk hazards against the design basis and provide a plan of actions to address vulnerabilities, including risks exceeding the design basis; (2) performance of walk downs to ensure the ability to respond to seismic and external flooding events and provide a corrective action plan to the NRC to address deficiencies; and (3) assessment of the means to provide power for communications equipment during a severe natural event and identify staffing required to implement the emergency plan for an event affecting all units with an extended loss of alternating current power and impeded access to the site. In November 2012, the NRC staff recommended to the NRC the installation of engineered containment filtered venting systems for boiling-water reactors with Mark I and Mark II containment structures. The NRC is currently reviewing the staff recommendations.

Generation has assessed the impacts of the orders and information requests and will continue monitoring the additional recommendations under review by the staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance is expected to be approximately $350 million and $50 million of capital and operating expense, respectively, from 2013 through 2017, as previously anticipated in Generation's planning projections. In addition, Generation estimates incremental costs of $15 to $20 million per unit at eleven Mark I and II units for the installation of filtered vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors, for further discussion of the risk factors.

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

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

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

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

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

Energy Infrastructure Modernization Act. Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. 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 3 of the Combined Notes to Consolidated Financial Statements for additional information.

FERC Ameren Order. In July 2012, FERC issued an order to Ameren Corporation indicating that Ameren had improperly included acquisition premiums/ goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren has filed for rehearing regarding the July 2012 FERC order. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/ goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

Reliability and Quality of Service Standards. During its 2011 legislative session, the Maryland General Assembly passed legislation:

- directing the MDPSC to enact service quality and reliability regulations by July 1, 2012 relating to the delivery of electricity to retail electric customers,
- increasing existing penalties for failure to meet these and other MDPSC regulations, and
- directing the MDPSC to undertake certain studies addressing utility liability for certain customer damages, electric utility service restoration plans, and modifications to existing revenue decoupling mechanisms for extended service interruptions.

In May 2011, the Governor of Maryland signed this legislation into law. The related new service quality and reliability regulations became effective on May 28, 2012. These regulations could have a material impact on BGE's financial results of operations, cash flows and financial position. BGE did seek recovery of these costs in the current base rate case filed on July 27, 2012.

2012 Maryland Electric and Gas Distribution Rate Case. On July 27, 2012, BGE filed an 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 updated its application to request an increase of $131 million and $45 million to its electric and gas base rates, respectively. The new electric and 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.

FERC Order No. 1000 Compliance (ComEd, PECO and BGE). In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC removed from all FERC-approved tariffs and agreements a federal right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners including ComEd, PECO and BGE (collectively, the PJM Transmission Owners) submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's "*Mobile-Sierra*" standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. Although this heightened standard of review should make it more difficult for the FERC or any third party to override the PJM Transmission Owners' right to build such transmission projects, there is risk that the FERC will find that the heightened standard of review does not apply to protect the PJM Transmission Owners rights and/or find that whatever standard is applied has been satisfied. Such a FERC finding could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP requires that management apply accounting policies and make estimates and assumptions that affect results of operations and the amounts of assets and liabilities reported in the financial statements. Management discusses these policies, estimates and assumptions with its accounting and disclosure governance committee on a regular basis and provides periodic updates on management decisions to the audit committee of the Exelon board of directors. Management believes that the areas described below require significant judgment in the application of accounting policy or in making estimates and assumptions that are inherently uncertain and that may change in subsequent periods. Additional discussion of the application of these accounting policies can be found in the Combined Notes to Consolidated Financial Statements.

Nuclear Decommissioning Asset Retirement Obligations

Generation must make significant estimates and assumptions in accounting for its obligation to decommission its nuclear generating plants in accordance with the authoritative guidance for AROs. Generation's ARO associated with decommissioning its nuclear units was $4.7 billion at December 31, 2012.

The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses an internally-developed, probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios. The nuclear decommissioning obligation is adjusted on a regular basis due to the passage of time and revisions to the key assumptions for the expected timing or estimated amounts of the future undiscounted cash flows required to decommission the nuclear plants, based upon the methodologies and significant estimates and assumptions described as follows:

Decommissioning Cost Studies. Generation uses unit-by-unit decommissioning cost studies to provide a marketplace assessment of the costs and timing of decommissioning activities, which are validated by comparison to current decommissioning projects within its industry and other estimates. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years.

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

Probabilistic Cash Flow Models. Generation's probabilistic cash flow models include the assignment of probabilities to various scenarios for decommissioning costs, approaches and timing on a unit-by-unit basis. Probabilities assigned to cost levels include an assessment of the likelihood of costs 20% higher (high-cost scenario) or 15% lower (low-cost scenario) than the base cost scenario. Probabilities are assigned to alternative decommissioning approaches which assess the likelihood of performing DECON (a method of decommissioning shortly after the cessation of operation in which the equipment, structures, and portions of a facility and site containing radioactive contaminants are removed and safely buried in a LLRW landfill or decontaminated to a level that permits property to be released for unrestricted use), Delayed DECON (similar to the DECON scenario but with a delay to allow for spent fuel to be removed from the site prior to onset of decommissioning activities) or SAFSTOR (a method of decommissioning in which the nuclear facility is placed and maintained in such condition that the nuclear facility can be safely stored and subsequently decontaminated to levels that permit release for unrestricted use generally within 60 years after cessation of operations) decommissioning. Probabilities assigned to the timing scenarios incorporate the likelihood of continued operation through current license lives or through anticipated license renewals. Generation's probabilistic cash flow models also include an assessment of the timing of DOE acceptance of SNF for disposal, which Generation assumed would begin in 2025 and 2020 in 2012 and 2011, respectively. The change in the SNF acceptance date was based on management's estimates of the amount of time required for the DOE to select a site location and develop the necessary infrastructure. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 19 of the Combined Notes to Consolidated Financial Statements.

License Renewals. Generation assumes a successful 20-year renewal for each of its nuclear generating station licenses, except for Oyster Creek, in determining its nuclear decommissioning ARO. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information on Oyster Creek. Generation has successfully secured 20-year operating license renewal extensions for ten of its nuclear units (including the two Salem units co-owned by Generation, but operated by PSEG), and none of Generation's applications for an operating license extension have been denied. Generation is in various stages of the process of pursuing similar extensions on its remaining nine operating nuclear units. Generation's assumption regarding license extension for ARO determination purposes is based in part on the good current physical condition and high performance of these nuclear units; the favorable status of the ongoing license renewal proceedings with the NRC, and the successful renewals for ten units to date. Generation estimates that the failure to obtain license renewals at any of these nuclear units (assuming all other assumptions remain constant) would increase its ARO on average approximately $250 million per unit as of December 31, 2012. The size of the increase to the ARO for a particular nuclear unit is dependent upon the current stage in its original license term and its specific decommissioning cost estimates. If Generation does not receive license renewal on a particular unit, the increase to the ARO may be mitigated by Generation's ability to delay ultimate decommissioning activities under a SAFSTOR method of decommissioning.

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

Under the current accounting framework, the ARO is not required or permitted to be re-measured, from period to period, for changes in the CARFR that occur in isolation. This differs from the accounting requirements for other long-dated obligations, such as pension and other post-employment benefits that are required to be re-measured as and when corresponding discount rates change. If Generation's future nominal cash flows associated with the ARO were to be discounted at current prevailing CARFRs, the obligation would increase from approximately $4.7 billion to approximately $7.5 billion. The ultimate decommissioning obligation will be funded by the NDTs. The NDTs are recorded on Exelon's and Generation's Consolidated Balance Sheets at December 31, 2012 at fair value of approximately $7.2 billion and have an estimated targeted annual pre-tax return of 5.3% to 6.2%.

To illustrate the significant impact that changes in the CARFR, when combined with changes in projected amounts and expected timing of cash flows, can have on the valuation of the ARO: i) had Generation used the 2011 CARFRs rather than the 2012 CARFRs in performing its third quarter 2012 ARO update, Generation would have reduced the ARO by approximately $50 million as compared to the actual increase to the ARO of $669 million; and ii) if the CARFR used in performing the third quarter 2012 ARO update (which also reflected increases in the amounts and changes to the timing of projected cash flows) was increased or decreased by 100 basis points, the ARO would have increased by $110 million and $1.6 billion, respectively, as compared to the actual increase of $669 million.

ARO Sensitivities. Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. The impact to the ARO of a change in any one of these assumptions is highly dependent on how the other assumptions will change as well. As an example, the significant changes in the value of the ARO during 2012 were driven primarily by Generation modifying the assumed timing of the DOE acceptance of SNF for disposal from 2020 to 2025 during the third quarter 2012 annual ARO update. The modification of the assumed DOE acceptance date impacted the calculation of the ARO in isolation as follows; i) the change in the timing of DOE acceptance of SNF increased the total number of years in which decommissioning activities are estimated to occur, by five years on average, thereby increasing the total expected nominal cash flows required to decommission the units; ii) the nominal cash flows were subjected to additional escalation as a result of the extension of the decommissioning period increasing the total estimated costs required to decommission the units; and iii) the escalated cash flows were then discounted at the then current CARFRs which have dramatically decreased in 2012 given the current low interest rate environment. The change in the timing and amount of cash flows as a result of the change in the assumed DOE acceptance date in combination with the significant decrease in the 2012 CARFRs were the primary drivers of the third quarter 2012 ARO update total increase of $669 million.

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

Change in ARO Assumption	Increase to ARO at December 31, 2012
Cost escalation studies	
Uniform increase in escalation rates of 25 basis points	$ 820
Probabilistic cash flow models	
Increase the likelihood of the high-cost scenario by 10 percentage points and decrease the likelihood of the low-cost scenario by 10 percentage points	$ 250
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$ 360
Increase the likelihood of operating through current license lives by 10 percentage points and decrease the likelihood of operating through anticipated license renewals by 10 percentage points	$ 490
Extend the estimated date for DOE acceptance of SNF to 2030	$ 700
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with an increase in discount rates of 100 basis points	$ 30
Extend the estimated date for DOE acceptance of SNF to 2030 coupled with a decrease in discount rates of 100 basis points	$1,570

For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 13 of the Combined Notes to Consolidated Financial Statements.

Goodwill

As of December 31, 2012, Exelon's and ComEd's carrying amount of goodwill was approximately $2.6 billion, relating to the acquisition of ComEd in 2000 as part of the PECO/Unicom Merger. Under the provisions of the authoritative guidance for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs, such as a significant negative regulatory outcome, or circumstances change that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Under the authoritative guidance, a reporting unit is an operating segment or operating component and is the level at which goodwill is tested for impairment. In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised guidance, which became effective January 1, 2012, entities assessing goodwill for impairment have the option of performing a qualitative assessment rather than the quantitative assessment previously required. In performing a qualitative assessment, entities should assess, among other things, macroeconomic conditions, industry and market considerations, overall financial performance, cost factors, and entity-specific events. If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not greater than the carrying amount, no further testing is required. If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. Application of the goodwill impairment test requires management judgment, including the identification of reporting units and determining the fair value of the reporting unit, which management estimates using a weighted combination of a discounted cash flow analysis and a market multiples analysis. Significant assumptions used in these fair value analyses include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows for ComEd's business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

ComEd performed an interim goodwill impairment assessment as of May 31, 2012, as a result of the ICC's final Order (Order) in ComEd's 2011 formula rate proceeding under the EIMA that reduced ComEd's annual revenue requirement being recovered in current rates by $168 million. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Based on the results of the interim goodwill test performed as of May 31, 2012, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and while certain factors indicated a reduction in fair value since May 31, 2012, ComEd determined its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment.

While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, a change in management's assumption regarding the outcome of the IRS challenge of Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA or changes in significant assumptions described above could potentially result in a future impairment of ComEd's goodwill, which could be material. ComEd will assess whether its goodwill has been impaired in the first quarter of 2013 in connection with the reassessment of the like-kind exchange position and the associated charge to ComEd's earnings. See Notes 1, 8 and 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting

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

Unamortized Energy Assets and Liabilities

Unamortized energy contract assets and liabilities represent the remaining unamortized balances of non-derivative energy contracts that Generation has acquired. The initial amount recorded represents the fair value of the contract at the time of acquisition, and the balance is amortized over the life of the contract in relation to the present value of the underlying cash flows. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Refer to Note 4—Mergers and Acquisitions and Note 8—Intangible Assets for further discussion.

Impairment of Long-lived Assets

Exelon evaluates its long-lived assets and asset groups, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. Conditions that could have an adverse impact on the cash flows and fair value of the long-lived assets are deteriorating business climate, including current energy prices and market conditions, condition of the asset, specific regulatory disallowance, or plans to dispose of a long-lived asset significantly before the end of its useful life, among others. Continued declines in natural gas prices have impacted fundamental views of market power prices, which could indicate a potential impairment to the Registrants' long-lived assets and asset groups, which are primarily made up of generating assets. The Registrants regularly monitor their long-lived assets for these circumstances to determine whether or not an impairment evaluation is required.

The review of long-lived assets and asset groups for impairment requires significant assumptions about operating strategies and estimates of future cash flows, which require assessments of current and projected market conditions. For the generation business, forecasting future cash flows requires assumptions regarding forecasted commodity prices for the sale of power, costs of fuel and the expected operations of assets. A variation in the assumptions used could lead to a different conclusion regarding the recoverability of an asset or asset group and, thus, could have a significant effect on the consolidated financial statements. An impairment evaluation is based on an undiscounted cash flow analysis at the lowest level at which cash flows of the long-lived assets or asset groups are largely independent of other groups of assets and liabilities. For the generation business, the lowest level of independent cash flows is determined by evaluation of several factors, including the geographic dispatch of the generation units and the hedging strategies related to those units and associated intangible contract assets recorded on the balance sheet. The cash flows from the generation units are evaluated at a regional portfolio level with cash flows generated from Generation's customer supply and risk management activities, including cash flows from contracts that are accounted for as intangible contract assets and liabilities recorded on the balance sheet. For ComEd, PECO and BGE, the lowest level of independent cash flows is determined by evaluation of several factors including the ratemaking jurisdiction in which they operate and the type of service or commodity provided. For ComEd, the lowest level of independent cash flows is transmission and distribution and for PECO and BGE, the lowest level of independent cash flows is transmission, distribution and gas.

Impairment may occur when the carrying value of the asset or asset group exceeds the future undiscounted cash flows. When the undiscounted cash flow analysis indicates a long-lived asset or asset group is not recoverable, the amount of the impairment loss is determined by measuring the excess of the carrying amount of the long-lived asset or asset group over its fair value. The fair value of the long-lived asset or asset group is dependent upon a market participant's view of the exit price of the assets. This includes significant assumptions of the estimated future cash flows generated by the assets and market discount rates. Events and circumstances frequently do not occur as expected and there will usually be differences between prospective financial information and actual results, and those differences may be material. Accordingly, to the extent that any of the information used in the fair value analysis requires adjustment, the resulting fair market value would be different. As such, the determination of fair value is driven by both internal assumptions as well as information from various public, financial and industry sources. An impairment determination would require the affected Registrant to reduce either the long-lived asset or asset group, including any intangible contract assets and liabilities, and current period earnings by the amount of the impairment.

Generation evaluates unproved gas producing properties at least annually to determine if they are impaired. Impairment for unproved gas property occurs if there are no firm plans to continue drilling, lease expiration is at risk, or historical experience necessitates a valuation allowance.

Exelon holds certain investments in coal-fired plants in Georgia and Texas subject to long-term leases. Exelon determines the investment in these plants by incorporating an estimate of the residual values of the leased assets which equates to the fixed purchase option prices established at the inception of the leases. On an annual basis, Exelon reviews the estimated residual values of these plants to determine if the current estimate of their residual value is lower than the one originally established. In determining the current estimate of the residual value the expectation of future market conditions, including commodity prices, is considered. If the current estimate of the residual value is lower than the residual value established at the inception of the lease and the decline is considered to be other than temporary, a loss will be recognized with a corresponding reduction to the carrying amount of the investment. To date, no such losses have been recognized.

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

See Note 4 of the Combined Notes to Consolidated Financial Statements for a discussion of asset impairment evaluations made by Generation.

Depreciable Lives of Property, Plant and Equipment

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

The estimated service lives of the nuclear generating facilities are based on the estimated useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses for all of Generation's operating nuclear generating stations except for Oyster Creek. While Generation has received license renewals for certain facilities, and has applied for or expects to apply for and obtain approval of license renewals for the remaining facilities, circumstances may arise that would prevent Generation from obtaining additional license renewals. Generation also evaluates every three to five years the estimated service lives of its fossil fuel generating and renewable facilities based on feasibility assessments as well as economic and capital requirements. The estimated service lives of hydroelectric facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the Conowingo and Muddy Run operating licenses. A change in depreciation estimates resulting from Generation's extension or reduction of the estimated service lives could have a significant effect on Generation's results of operations. Generation completed a depreciation rate study during the first quarter of 2010, which resulted in the implementation of new depreciation rates effective January 1, 2010. Constellation completed a depreciation rate study during the fourth quarter of 2010, which resulted in the implementation of new depreciation rates effective during the fourth quarter of 2010.

ComEd is required to file a depreciation rate study at least every five years with the ICC. ComEd filed a depreciation rate study with the ICC in January 2009, which resulted in the implementation of new depreciation rates effective January 1, 2009.

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

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

Defined Benefit Pension and Other Postretirement Benefits

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO, BGE and BSC employees. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding the accounting for the defined benefit pension plans and other postretirement benefit plans.

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit pension and other postretirement benefit plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, the anticipated rate of increase of health care costs, Exelon's expected level of contributions to the plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the long-term expected investment rate credited to employees of certain plans, among others. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. Pension and other postretirement benefit costs attributed to the operating companies are labor costs and are ultimately allocated to projects within the operating companies, some of which are capitalized.

Pension and other postretirement benefit plan assets include equity securities, including U.S. and international securities, and fixed income securities, as well as certain alternative investment classes such as real estate, private equity and hedge funds. See Note 14 of the Combined Notes to Consolidated Financial Statements for information on fair value measurements of pension and other postretirement plan assets, including valuation techniques and classification under the fair value hierarchy in accordance with authoritative guidance.

Expected Rate of Return on Plan Assets. The long-term expected rate of return on plan assets assumption used in calculating pension costs was 7.50%, 8.00% and 8.50% for 2012, 2011 and 2010, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 6.68%, 7.08% and 7.83% in 2012, 2011 and 2010, respectively. The pension trust activity is non-taxable, while other postretirement benefit trust activity is partially taxable. The current year EROA is based on asset allocations from the prior year end. In 2010, Exelon began implementation of a liability driven investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, over time, Exelon determined that it will decrease equity investments and increase investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return-generating assets. The change in the overall investment strategy would tend to lower the expected rate of return on plan assets in future years as compared to the previous strategy. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.50% and 6.45% to estimate its 2013 pension and other postretirement benefit costs, respectively.

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

Actual asset returns have an impact on the costs reported for the Exelon-sponsored pension and other postretirement benefit plans. The actual asset returns across the Registrants' pension and other postretirement benefit plans for the year ended December 31, 2012 were 12.8% and 12.5%, respectively, compared to an expected long-term return assumption of 7.50% and 6.68%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations were 3.92% and 4.00%, respectively, at December 31, 2012. The discount rates at December 31, 2012 represent weighted-average rates for both legacy Exelon and Constellation pension and other postretirement benefit plans. At December 31, 2012 and 2011, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high-quality non-callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 3.92% and 4.00% to estimate its 2013 pension and other postretirement benefit costs, respectively.

Health Care Reform Legislation. In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, the Registrants were required to recognize the full accounting impact in their financial statements in the period in which the legislation was enacted. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon changed the manner in which it will receive prescription drug subsidies beginning in 2013.

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

Health Care Cost Trend Rate. Assumed health care cost trend rates have a significant effect on the costs reported for Exelon's other postretirement benefit plans. Accounting guidance requires that annual health care cost estimates be developed using past and present health care cost trends (both for Exelon and across the broader economy), as well as expectations of health care cost escalation, changes in health care utilization and delivery patterns, technological advances and changes in the health status of plan participants. Therefore, the trend rate assumption is subject to significant uncertainty, particularly when considering potential impacts of the 2010 Health Care Reform Acts. Exelon assumed an initial health care cost trend rate of 6.50% at December 31, 2012, decreasing to an ultimate health care cost trend rate of 5.00% in 2017.

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

Actuarial Assumption	Change in Assumption	Pension	Other Postretirement Benefits	Total
Change in 2012 cost:				
Discount rate [(a)]	0.5%	$ (61)	$ (26)	$ (87)
	(0.5%)	60	29	89
EROA	0.5%	(66)	(9)	(75)
	(0.5%)	66	9	75
Health care cost trend rate	1.00%	N/A	81	81
	(1.00%)	N/A	(56)	(56)
Change in benefit obligation at December 31, 2012:				
Discount rate [(a)]	0.5%	(987)	(340)	(1,327)
	(0.5%)	1,094	367	1,461
Health care cost trend rate	1.00%	N/A	845	845
	(1.00%)	N/A	(569)	(569)

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

Average Remaining Service Period. For pension benefits, Exelon amortizes its unrecognized prior service costs and certain actuarial gains and losses, as applicable, based on participants' average remaining service periods. The average remaining service period of defined benefit pension plan participants was 11.9 years, 12.1 years and 12.4 years for the years ended December 31, 2012, 2011 and 2010, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized prior service costs over participants' average remaining service period to benefit eligibility age and amortizes its transition obligations and certain actuarial gains and losses over participants' average remaining service period to expected retirement. The average remaining service period of postretirement benefit plan participants related to benefit eligibility age was 8.9 years, 6.6 years and 6.8 years for the years ended December 31, 2012, 2011 and 2010, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 10.1 years, 8.7 years and 9.0 years for the years ended December 31, 2012, 2011 and 2010, respectively.

Regulatory Accounting

Exelon, ComEd, PECO and BGE account for their regulated electric and gas operations in accordance with the authoritative guidance for accounting for certain types of regulations, which requires Exelon, ComEd, PECO and BGE to reflect the effects of cost-based rate regulation in their financial statements. This guidance is applicable to entities with regulated operations that meet the following criteria: (1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) a reasonable expectation that rates are set at levels that will recover the entities costs from customers. Regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent (1) the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates; or (2) billings in advance of expenditures for approved regulatory programs. As of December 31, 2012, Exelon, ComEd, PECO and BGE have concluded that the operations of ComEd, PECO and BGE meet the criteria to apply the authoritative guidance. If it is concluded in a future period that a separable portion of those operations no longer meets the criteria of this guidance, Exelon, ComEd, PECO and BGE would be required to eliminate any associated regulatory assets and liabilities and the impact would be recognized in the Consolidated

Statements of Operations and could be material. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd, PECO and BGE.

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

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

Accounting for Derivative Instruments

Exelon utilizes derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy-related products marketed and purchased. Additionally, Generation enters into energy-related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd has a financial swap contract with Generation that extends into 2013 and floating-to-fixed energy swaps with several unaffiliated suppliers that extend into 2032. PECO has entered into derivative natural gas contracts to hedge its long-term price risk in the natural gas market. PECO has also entered into derivative contracts to procure electric supply through a competitive RFP process as outlined in its PAPUC-approved DSP Program. BGE has also entered into derivative contracts to procure electric supply through a competitive auction process as outlined in its MDPSC-approved SOS Program. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes. The Registrants' derivative activities are in accordance with Exelon's Risk Management Policy (RMP). See Note 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

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

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

Normal Purchases and Normal Sales Exception. Determining whether a contract qualifies for the normal purchases and normal sales exception requires that management exercise judgment on whether the contract will physically deliver and requires that management ensure compliance with all of the associated qualification and documentation requirements. Revenues and expenses on contracts that qualify as normal purchases and normal sales are recognized when the underlying physical transaction is completed. Contracts which qualify for the normal purchases and normal sales exception are those for which physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and is not financially settled on a net basis. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the retail and wholesale markets with the intent and ability to deliver or take delivery. While some of these contracts are considered derivative financial instruments under the authoritative guidance, certain of these qualifying transactions have been designated as normal purchases and normal sales and are thus not required to be recorded at fair value, but rather on an accrual basis of accounting. The contracts that ComEd has entered into with Generation and other suppliers as part of ComEd's energy procurement process, PECO's full requirement contracts and block contracts under the PAPUC-approved DSP program, most of PECO's natural gas supply agreements and all of BGE's full requirement contracts and natural gas supply agreements that are derivatives qualify for the normal purchases and normal sales exception. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the scope exceptions, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd, PECO and BGE. Thereafter, future changes in fair value would be recorded in the balance sheet and recognized through earnings at Generation. Triggering events that could result in a contract's loss of the normal purchase and normal sale designation, because it is no longer probable that the contract will result in physical delivery, include changes in business requirements, changes in counterparty credit and financial rather than physical contract settlements.

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

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

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

See Quantitative and Qualitative Disclosures about Market Risk and Notes 9 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation

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

Exelon evaluates quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and its intent and ability to implement tax planning strategies, if necessary, to realize deferred tax assets. Exelon also assesses its ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. Exelon records valuation allowances for deferred tax assets when it concludes it is more-likely-than-not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2012 and 2011 are appropriately accounted for in accordance with the applicable authoritative guidance, the ultimate outcome of tax matters could result in favorable or unfavorable adjustments to their consolidated financial statements and such adjustments could be material. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

Accounting for Loss Contingencies

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

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which Exelon will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Periodic studies are conducted at ComEd, PECO and BGE to determine future remediation requirements and estimates are adjusted accordingly. In addition, periodic reviews are performed at Generation to assess the adequacy of its environmental reserves. These matters, if resolved in a manner different from the estimate, could have a significant effect on Exelon's results of operations, financial position and cash flows. See Note 19 of the Combined Notes to Consolidated Financial Statements for further information.

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

Revenue Recognition

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

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

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

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

The determination of Generation's energy sales, excluding the retail business, is based on estimated amounts delivered as well as fixed quantity sales. At the end of each month, amounts of energy delivered to customers during the month are estimated and the corresponding unbilled revenue is recorded. Increases in volumes delivered to the wholesale customers in the period, as well as price, would increase unbilled revenue.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects Exelon's best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on historical specific customer payment experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 5 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounts receivable.

Results of Operations by Business Segment

The comparisons of operating results and other statistical information for the years ended December 31, 2012, 2011 and 2010 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Net Income (Loss) on Common Stock by Business Segment

	2012 [(a)]	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Exelon	$1,160	$2,495	$(1,335)	$2,563	$ (68)
Generation	562	1,771	(1,209)	1,972	(201)
ComEd	379	416	(37)	337	79
PECO	377	385	(8)	320	65
BGE	(9)	123	(132)	134	(11)

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

Results of Operations—Generation

	2012 (b)	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$14,437	$10,447	$ 3,990	$10,025	$ 422
Purchased power and fuel expense	7,061	3,589	(3,472)	3,463	(126)
Revenue net of purchased power and fuel expense (a)	7,376	6,858	518	6,562	296
Other operating expenses					
Operating and maintenance	5,028	3,148	(1,880)	2,812	(336)
Depreciation and amortization	768	570	(198)	474	(96)
Taxes other than income	369	264	(105)	230	(34)
Total other operating expenses	6,165	3,982	(2,183)	3,516	(466)
Equity in losses of unconsolidated affiliates	(91)	(1)	(90)	—	(1)
Operating income	1,120	2,875	(1,755)	3,046	(171)
Other income and (deductions)					
Interest expense	(301)	(170)	(131)	(153)	(17)
Other, net	239	122	117	257	(135)
Total other income and (deductions)	(62)	(48)	(14)	104	(152)
Income before income taxes	1,058	2,827	(1,769)	3,150	(323)
Income taxes	500	1,056	556	1,178	122
Net income	558	1,771	(1,213)	1,972	(201)
Net loss attributable to noncontrolling interest	(4)	—	(4)	—	—
Net income on common stock	$ 562	$ 1,771	$(1,209)	$ 1,972	$(201)

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

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

Net Income

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. Generation's net income decreased compared to the same period in 2010 primarily due to mark-to-market losses on economic hedging activities and higher operating and maintenance expenses. Generation's 2011 results were further affected by increased nuclear fuel costs, less favorable NDT fund performance in 2011 and higher nuclear refueling outage costs associated with the increased number of refueling outage days in 2011. These unfavorable impacts were partially offset by higher revenues due to the expiration of the PECO PPA on December 31, 2010 and favorable market and portfolio conditions in the ERCOT region.

Revenue Net of Purchased Power and Fuel Expense

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

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

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in natural gas exploration and production activities, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems. Further, the following activities are not allocated to a region, and are reported in Other: compensation under the reliability-must-run rate schedule; results of operations from the Maryland Clean-Coal assets sold in Q4 2012; unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger; and other miscellaneous revenues.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense which is a non-GAAP measurement. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for internally generated energy and fuel costs associated with tolling agreements.

For the year ended December 31, 2012 compared to 2011 and 2011 compared to 2010, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2012 vs. 2011			2011 vs. 2010	
	2012 (a)	2011	Variance	% Change	2010	Variance	% Change
Mid-Atlantic (b)(f)	$3,433	$3,350	$ 83	2.5%	$2,501	$ 849	33.9%
Midwest (c)	2,998	3,547	(549)	(15.5)%	4,081	(534)	(13.1)%
New England	196	9	187	n.m.	11	(2)	n.m.
New York (f)	76	—	76	n.m.	—	—	n.m.
ERCOT	405	84	321	n.m.	(65)	149	n.m.
Other Regions (d)	131	(14)	145	n.m.	(66)	52	n.m.
Total electric revenue net of purchased power and fuel expense	$7,239	$6,976	$ 263	3.8%	$6,462	$ 514	8.0%
Proprietary Trading	(14)	24	(38)	n.m.	27	(3)	(11.1)%
Mark-to-market gains (losses)	515	(288)	803	n.m.	86	(374)	n.m.
Other (e)	(364)	146	(510)	n.m.	(13)	159	n.m.
Total revenue net of purchased power and fuel expense	$7,376	$6,858	$ 518	7.6%	$6,562	$ 296	4.5%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
(c) Results of transactions with ComEd are included in the Midwest region.
(d) Other Regions includes South, West and Canada, which are not considered individually significant.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at merger date of $1,098 million pre-tax for the twelve months ended December 31, 2012.
(f) Includes $487 million and $306 million of purchase power from CENG in the Mid-Atlantic and New York regions, respectively. See Note 22 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's supply sources by region are summarized below:

			2012 vs. 2011			2011 vs. 2010	
Supply source (GWh)	**2012 (a)**	**2011**	**Variance**	**% Change**	**2010**	**Variance**	**% Change**
Nuclear generation (b)							
Mid-Atlantic	47,337	47,287	50	0.1%	47,517	(230)	(0.5)%
Midwest	92,525	92,010	515	0.6%	92,493	(483)	(0.5)%
	139,862	139,297	565	0.4%	140,010	(713)	(0.5)%
Fossil and renewables (b)							
Mid-Atlantic (b)(d)	8,808	7,572	1,236	16.3%	9,426	(1,854)	(19.7)%
Midwest	971	596	375	62.9%	68	528	n.m.
New England	9,965	8	9,957	n.m.	10	(2)	(20.0)%
ERCOT (e)	6,182	2,030	4,152	n.m.	1,129	901	79.8%
Other Regions (f)	5,913	1,432	4,481	n.m.	84	1,348	n.m.
	31,839	11,638	20,201	n.m.	10,717	921	8.6%
Purchased power							
Mid-Atlantic (c)	20,830	2,898	17,932	n.m.	1,918	980	51.1%
Midwest	9,805	5,970	3,835	64.2%	7,032	(1,062)	(15.1)%
New England	9,273	—	9,273	n.m.	—	—	n.m.
New York (c)	11,457	—	11,457	n.m.	—	—	n.m.
ERCOT (e)	23,302	7,537	15,765	n.m.	9,494	(1,957)	(20.6)%
Other Regions (f)	17,327	2,503	14,824	n.m.	2,618	(115)	(4.4)%
	91,994	18,908	73,086	n.m.	21,062	(2,154)	(10.2)%
Total supply by region (g)							
Mid-Atlantic (h)	76,975	57,757	19,218	33.3%	58,861	(1,104)	(1.9)%
Midwest (i)	103,301	98,576	4,725	4.8%	99,593	(1,017)	(1.0)%
New England	19,238	8	19,230	n.m.	10	(2)	n.m.
New York	11,457	—	11,457	n.m.	—	—	n.m.
ERCOT	29,484	9,567	19,917	n.m.	10,623	(1,056)	(9.9)%
Other Regions (f)	23,240	3,935	19,305	n.m.	2,702	1,233	45.6%
Total supply	263,695	169,843	93,852	55.3%	171,789	(1,946)	(1.1)%

(a) Includes results for Constellation business transferred to Generation beginning on March 12, 2012, the date the merger was completed.
(b) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and does not include ownership through equity method investments (e.g. CENG).
(c) Purchased power includes physical volumes of 9,925 GWh in the Mid-Atlantic and 9,350 GWh in New York as a result of the PPA with CENG for the year ended December 31, 2012.
(d) Excludes generation under the reliability-must-run rate schedule and generation of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 as a result of the Exelon and Constellation merger.
(e) Generation from Wolf Hollow is included in purchased power through the acquisition date of August 24, 2011, and included within Fossil and Renewables subsequent to the acquisition date.
(f) Other Regions includes South, West and Canada, which are not considered individually significant.
(g) Excludes physical proprietary trading volumes of 12,958 GWh, 5,742 GWh and 3,625 GWh for the years ended December 31, 2012, 2011 and 2010 respectively.
(h) Includes sales to PECO through the competitive procurement process of 7,762 GWh, 7,041 GWh, and 42,003 GWh for the years ended December 31, 2012, 2011 and 2010 respectively. Sales to BGE of 3,766 GWh were included for the year ended December 31, 2012.
(i) Includes sales to ComEd under the RFP procurement of 4,152 GWh, 4,731 GWh and 8,218 GWh for the years ended December 31, 2012, 2011 and 2010 respectively.

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2012 as compared to the same period in 2011 and 2011 as compared to the same period in 2010.

$/MWh	2012 (a)	2011	2012 vs. 2011 % Change	2010	2011 vs. 2010 % Change
Mid-Atlantic (b)	$44.60	$58.00	(23.1)%	$ 42.48	36.5%
Midwest (c)	29.02	35.99	(19.4)%	40.98	(12.2)%
New England	10.19	n.m.	n.m.	—	n.m.
New York	6.63	n.m.	n.m.	—	n.m.
ERCOT	13.74	8.78	56.5%	(6.24)	n.m.
Other Regions (d)	5.64	(3.56)	n.m.	(23.97)	85.1%
Electric revenue net of purchased power and fuel expense per MWh (e)(f)	$27.45	$41.07	(33.2)%	$ 37.62	9.2%

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

(b) Includes sales to PECO of $536 million (7,762 GWh), $508 million (7,041 GWh) and $2,091 million (42,003 GWh) for the years ended December 31, 2012, 2011 and 2010, respectively. Sales to BGE of $322 million (3,766 GWH) were included for the year ended December 31, 2012. Excludes compensation under the reliability-must-run rate schedule and the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the merger.

(c) Includes sales to ComEd of $162 million (4,152 GWh), $179 million (4,731 GWh) and $288 million (8,218 GWhs) and settlements of the ComEd swap of $627 million, $474 million and $385 million for years ended December 31, 2012, 2011 and 2010, respectively.

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

(e) Revenue net of purchased power and fuel expense per MWh represents the average margin per MWh of electricity sold during the years ended December 31, 2012, 2011 and 2010, respectively, and excludes the mark-to-market impact of Generation's economic hedging activities.

(f) Excludes retail gas activity, proprietary trading portfolio activity, compensation under the reliability-must-run rate schedule and fuel sales. Also excludes results from energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, excludes the financial results of Brandon Shores, H.A. Wagner, and C.P. Crane, the generating facilities divested in Q4 2012 as a result of the Exelon and Constellation merger. Also excludes amortization of intangible assets relating to commodity contracts recorded at fair value at the merger date.

Mid-Atlantic

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $849 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to increased margins on the volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, partially offset by increased nuclear fuel costs.

Midwest

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $534 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to decreased realized margins in 2011 for the volumes previously sold by Generation under the 2006 ComEd auction contracts and increased nuclear fuel costs. These decreases were partially offset by increased capacity revenues, favorable settlements under the ComEd swap and the additional revenue following the acquisition of Exelon Wind in December 2010.

New England

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

New York

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

ERCOT

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $149 million increase in revenue net of purchased power and fuel expense in the ERCOT was primarily driven by the performance of Generation's generating units during extreme weather events that occurred in Texas in February and August 2011.

Other Regions

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $52 million increase in revenue net of purchased power and fuel expense in Other Regions was due to the impact of additional revenue from the acquisition of Exelon Wind in December 2010, as well as higher margins due to overall favourable market conditions.

Mark-to-market

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were $515 million in 2012 compared to losses of $288 million in 2011. See Notes 7 and 8 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market losses on economic hedging activities were $288 million in 2011 compared to gains of $86 million in 2010. See Notes 7 and 8 of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Other

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The $510 million decrease in other revenue net of purchased power and fuel was primarily due to the amortization of the acquired energy contracts recorded at fair value at the merger date. This decrease was partially offset by results from activities acquired as part of the merger including retail gas, energy efficiency, energy management and demand response, upstream natural gas and the design and construction of renewable energy facilities. In addition, other revenue net of purchased power and fuel includes the results of Brandon Shores, H.A. Wagner and C.P. Crane, the generating facilities divested in Q4 as a result of the Exelon and Constellation merger. See Note 4 of the Combined Notes to Consolidated Financial Statements for information regarding contract intangibles and assets planned for divestiture as a result of the Constellation merger.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $159 million increase in other revenue net of purchased power and fuel was primarily due the impacts of the impairment charge of certain emissions allowances recognized in 2010, additional other wholesale fuel sales in 2011 as well as compensation under the reliability-must-run rate schedule further described in Note 15 of the Combined Notes to Consolidated Financial Statements.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2012, as compared to 2011 and 2010, for the Exelon-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures to analyze the nuclear fleet performance between periods. Generation has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, these measures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or be more useful than the GAAP information provided elsewhere in this report.

	2012	2011	2010
Nuclear fleet capacity factor (a)	92.7%	93.3%	93.9%
Nuclear fleet production cost per MWh (a)	$19.50	$18.86	$17.31

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

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of planned refueling outage days. For 2011 and 2010, planned refueling outage days totaled 283 and 261, respectively. Lower generation, higher nuclear fuel costs and higher plant operating and maintenance costs resulted in a higher production cost per MWh during 2011 as compared to 2010.

Operating and Maintenance Expense

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

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

(a) Represents expense recorded during the third quarter of 2012 due to the reduction in book value. Upon completion of the November 30, 2012 transaction, Generation recorded a $6 million gain within Other, net in its Consolidated Statements of Operations and Comprehensive Income. The net loss on the sale of the Maryland Clean Coal assets was $272 million. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.
(b) Reflects costs incurred as part of a March 2012 settlement with the FERC to resolve a dispute related to Constellation's prior period hedging and risk management transactions.
(c) Reflects an increased share of corporate allocated costs due to the merger.
(d) Reflects costs incurred as part of the Maryland order approving the merger.
(e) Reflects the impact of decreased planned refueling outages during 2012.

The changes in operating and maintenance expense for 2011 compared to 2010, consisted of the following:

	Increase (Decrease)
Labor, other benefits, contracting and materials	$113
Nuclear refueling outage costs, including the co-owned Salem Plant [(a)]	74
Exelon Wind [(b)]	39
Asset retirement obligation reduction [(c)]	28
2010 nuclear insurance credit [(d)]	20
Corporate allocations [(e)]	19
Acquisition costs [(f)]	14
Other [(g)]	29
Increase in operating and maintenance expense	$336

(a) Reflects the impact of increased planned refueling outages during 2011.
(b) Includes $30 million in 2011 associated with labor, other benefits, contracting and materials at Exelon Wind.
(c) Reflects an increase in Generation's decommissioning obligation for spent fuel at Zion station. See Note 13 of the Combined Notes to Consolidated Financial Statements for further information.
(d) Reflects the impact of the return of property and business interruption insurance premiums in 2010. No premiums were returned for 2011.
(e) Primarily reflects increased lobbying costs related to EPA and competitive market matters.
(f) Reflects increase in certain costs associated with the acquisitions of Constellation, Exelon Wind, Wolf Hollow and Antelope Valley incurred in 2011. See Note 4 of the Combined Notes to Consolidated Financial Statements for further information.
(g) Includes additional environmental remediation costs recorded during 2011.

Depreciation and Amortization

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in depreciation and amortization expense was primarily a result of higher plant balances due to the acquisition of Exelon Wind, capital additions and other upgrades to existing facilities. Higher plant balances resulted in an increase in depreciation and amortization expense of $61 million. The remaining increase in depreciation and amortization expense was due to the impact of increases in asset retirement costs (ARC) for Generation's nuclear generating facilities.

Taxes Other Than Income

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase was primarily due to increased gross receipt taxes related to retail sales in the Mid-Atlantic region. These gross receipt taxes are recovered in revenue, and as a result, have no impact to Generation's results of operations.

Equity in Losses of Unconsolidated Affiliates

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Equity in losses of unconsolidated affiliates in 2012 primarily reflected $172 million related to the amortization of the basis difference in CENG recorded at fair value at the merger date, partially offset by $73 million of net income generated from Exelon's equity investment in CENG.

Interest Expense

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

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in interest expense is primarily due to debt issuances in 2010, further described in Note 11 of the Combined Notes to Consolidated Financial Statements. The increase in long-term debt resulted in higher interest expense of approximately $27 million.

Other, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in other, net primarily reflects net realized and unrealized gains related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net realized and unrealized losses in 2011, as described in the table below. Additionally, the increase reflects $117 million and $18 million of income in 2012 and 2011, respectively, related to the contractual elimination of income tax expense associated with the NDT funds of the Regulatory Agreement Units, $85 million of credit facility termination fees recorded in 2012, a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow and the impact of a $32 million one-time interest income from the NDT fund special transfer tax deduction in 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The decrease in other, net primarily reflects net unrealized losses in 2011 related to the NDT funds of Generation's Non-Regulatory Agreement Units compared to net unrealized gains in 2010, as described in the table below. Additionally, the decrease reflects the contractual elimination of $18 million of income tax expense associated with the NDT funds of the Regulatory Agreement Units in 2011 compared to the contractual elimination of $96 million of income tax expense in 2010. These decreases are partially offset by the $32 million impact of one-time interest income from the NDT fund special transfer tax deduction recognized in 2011 and a $36 million bargain purchase gain associated with the August 2011 acquisition of Wolf Hollow.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in other, net for 2012, 2011 and 2010:

	2012	2011	2010
Net unrealized gains (losses) on decommissioning trust funds	$105	$ (4)	$104
Net realized gains (losses) on sale of decommissioning trust funds	$ 51	$(10)	$ 2

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 47.3%, 37.4% and 37.4%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Results of Operations—ComEd

	2012	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$5,443	$6,056	$(613)	$6,204	$(148)
Purchased power expense	2,307	3,035	728	3,307	272
Revenue net of purchased power expense [(a)]	3,136	3,021	115	2,897	124
Other operating expenses					
Operating and maintenance	1,345	1,189	(156)	1,069	(120)
Depreciation and amortization	610	554	(56)	516	(38)
Taxes other than income	295	296	1	256	(40)
Total other operating expenses	2,250	2,039	(211)	1,841	(198)
Operating income	886	982	(96)	1,056	(74)
Other income and (deductions)					
Interest expense, net	(307)	(345)	38	(386)	41
Other, net	39	29	10	24	5
Total other income and (deductions)	(268)	(316)	48	(362)	46
Income before income taxes	618	666	(48)	694	(28)
Income taxes	239	250	11	357	107
Net income	$ 379	$ 416	$ (37)	$ 337	$ 79

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

Net Income

Year Ended December 31, 2012, Compared to Year Ended December 31, 2011. ComEd's net income for the year ended December 31, 2012, was lower than the same period in 2011 primarily due to lower electric distribution rates, effective June 20, 2012, pursuant to the ICC Order in the initial formula filing under EIMA. Offsetting the impact of the lower rates were increases in revenue resulting from the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, net of lower allowed return on equity. Additionally, offsetting the impacts of lower electric distribution rates was increased transmission revenue during 2012. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

The increase in operating and maintenance expenses reflect increases in contracting and labor expenses as a result of the first year of the ten-year grid modernization project related to EIMA. Operating and maintenance costs also increased as a result of increased pension and other non-pension and postretirement benefits expenses due to the impact of lower actuarially assumed discount rates and expected return on plan assets for 2012 as compared to 2011. Additionally, operating and maintenance costs were higher in 2012 due to one-time net benefits recognized in 2011 pursuant to the May 2011 ICC order in ComEd's 2010 rate case.

Year Ended December 31, 2011, Compared to Year Ended December 31, 2010. The increase in ComEd's net income was primarily due to higher electric distribution rates, effective June 1, 2011, pursuant to the ICC order in the 2010 Rate Case, and increased revenues resulting from the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA, which became effective in the fourth quarter of 2011. Net income was also higher due to the re-measurement of uncertain income tax positions in 2010 related to the 1999 sale of ComEd's fossil generating assets. The re-measurement resulted in increased interest expense and income tax expense recorded in 2010. These increases to net income were partially offset by higher operating and maintenance expense and taxes other than income.

The increase in operating and maintenance expense reflects the benefit recorded in 2010 resulting from the ICC's approval of ComEd's uncollectible accounts expense rider mechanism, a reduction in ComEd's ARO reserve in 2010, and higher labor and contracting expenses incurred in 2011. These increases to operating and maintenance expense were partially offset by one-time net benefits recognized pursuant to the ICC order in ComEd's 2010 rate case.

Operating Revenues and Purchased Power Expense

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

Electric revenues and purchased power expense are affected by fluctuations in customers' purchases from competitive electric generation suppliers. All ComEd customers have the ability to purchase electricity from an alternative electric generation supplier. The customer choice of electric generation supplier does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and generation services. The number of retail customers purchasing electricity from competitive electric generation suppliers was 1,627,150 and 380,262 at December 31, 2012, and 2011, respectively, representing 43% and 10% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 65% and 56% of ComEd's retail kWh sales at December 31, 2012, and 2011, respectively. On March 20, 2012, approximately 170 Illinois municipalities approved referenda regarding electric supply aggregation. This approval allowed municipal officials to identify and sign contracts with alternative retail electric suppliers. With few exceptions, these municipalities have identified and switched to alternative retail electric suppliers as of December 31, 2012. The City of Chicago and approximately 70 other municipalities and townships passed similar referenda in November 2012. The City of Chicago switching will occur in the first quarter of 2013. All or some of the other 70 municipalities and townships are also expected to switch during the first half of 2013. As contracts with new retail electric suppliers take effect, ComEd expects the percentage of retail deliveries purchased from retail electric suppliers to continue to increase. It is anticipated that by the end of the second quarter 2013 approximately 72% of retail customers and 82% of kWh sales in the ComEd region will be supplied by competitive retail electric suppliers.

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

	Increase (Decrease)
Electric distribution revenues	$ 40
Transmission	40
Regulatory required programs cost recovery	32
Revenues subject to refund, net	4
Weather delivery	2
Volume delivery	(4)
Other	1
Total increase	$115

Electric distribution revenues

In 2011, the ICC issued an order in the 2010 Rate Case approving an increase in ComEd's annual revenue requirement. The order became effective June 1, 2011, resulting in higher revenues for the first six months ended June 30, 2012, compared to the same period in 2011. Offsetting this increase was the lower rates which went into effect June 20, 2012, resulting from the May Order issued in ComEd's 2011 formula rate proceeding under EIMA. Additionally, electric distribution revenues increased as a result of the annual reconciliation of ComEd's distribution revenue requirement pursuant to EIMA. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Transmission

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's most recent annual formula rate update, filed in May 2012, reflects actual 2011 expenses and investments plus forecasted 2012 capital additions. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. ComEd set a record for the highest daily peak load of 23,753 MWs on July 20, 2011, which was reflected in the determination of transmission revenues billed beginning January 1, 2012, and transmission rates that went into effect on June 1, 2012. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory required programs cost recovery

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

Revenues subject to refund, net

ComEd records revenues subject to refund based upon its best estimate of customer collections that may be required to be refunded. During the year ended December 31, 2012, ComEd did not record material revenues subject to refund associated with any matters. As a result of the September 30, 2010, Illinois Appellate Court (Court) decision in the 2007 Rate Case which ruled against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via Rider SMP, ComEd began recording revenue subject to refund prospectively. In addition, ComEd began recording revenue subject to refund on June 1, 2010, relating to the recovery of Cash Working Capital (CWC) through its energy procurement rider. Based on the 2010 Rate Case order as well as the order on remand associated with the Court order, during the third quarter 2011 ComEd reduced its revenue subject to refund reserve. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information on these proceedings.

Weather—delivery

The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as "favorable weather conditions" because these weather conditions result in increased customer usage and delivery of electricity. Conversely, mild weather reduces demand. The favorable weather conditions for the year ended December 31, 2012, resulted in an increase in revenues net of purchased power expense.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the years ended December 31, 2012, and 2011, consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	5,065	6,134	6,341	(17.4)%	(20.1)%
Cooling Degree-Days	1,324	1,036	842	27.8%	57.2%

Volume—delivery

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential customer for 2012, compared to 2011.

Other

Other revenues were higher during the year ended December 31, 2012, compared to 2011. Other revenues, which can vary period to period, include rental revenues, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs, recoveries of environmental costs associated with MGP sites and recoveries under ComEd's uncollectible accounts tariff.

The changes in ComEd's electric revenue net of purchased power expense for 2011 compared to 2010 consisted of the following:

	Increase (Decrease)
Pricing (2010 Rate Case)	$ 89
Revenues subject to refund, net	31
Distribution formula rate reconciliation	29
Regulatory required programs cost recovery	21
Transmission	18
2007 City of Chicago settlement	2
Volume—delivery	(10)
Weather—delivery	(21)
Uncollectible accounts recovery, net	(33)
Other	(2)
Total increase	$124

Pricing (2010 Rate Case)

The ICC issued an order in the 2010 Rate Case approving an increase in ComEd's annual electric distribution revenue requirement. The order became effective June 1, 2011, resulting in higher revenues for the year ended December 31, 2011, compared to the same period in 2010. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Revenues subject to refund, net

As a result of the September 30, 2010, Court decision in the 2007 Rate Case ComEd began recording revenue subject to refund prospectively. In addition, ComEd began recording revenue subject to refund on June 1, 2010, relating to the recovery of Cash Working Capital (CWC) through its energy procurement rider. As a result of the 2010 rate case order, ComEd reduced its revenue subject to refund reserve during the third quarter of 2011. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Distribution formula rate reconciliation

EIMA provides for a performance-based formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. ComEd made its initial reconciliation filing in May 2012 and the adjusted rates will take effect in January 2013. At December 31, 2011, ComEd had recorded an estimated reconciliation of approximately $29 million which did not include the reconciliation of significant storm costs discussed under operating and maintenance expense below. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Regulatory required programs cost recovery

Revenues related to regulatory required programs are the recoveries from customers of costs for various legislative and/or regulatory programs on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating and maintenance for regulatory required programs during the period presented. See Note 3 of the Combined Notes to Financial Statements for additional information.

Transmission

ComEd's transmission rates are established based on a FERC-approved formula. ComEd's 2010 formula rate update, filed in May 2011, reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. Transmission revenues net of purchased power expense vary from year to year based upon fluctuations in the underlying costs and investments being recovered.

2007 City of Chicago Settlement

ComEd paid $1 million and $3 million in 2011 and 2010, respectively, under the terms of its 2007 settlement agreement with the City of Chicago. Payments were recorded as a reduction to revenues; therefore, the lower payment in 2011 resulted in a net increase in revenues net of purchased power expense for 2011 compared to 2010.

Volume—delivery

Revenues net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per residential and small commercial and industrial customer for 2011 compared to 2010.

Weather—delivery

The increase in revenues net of purchased power expense in 2011 compared to 2010 were partially offset by unfavorable weather conditions, despite setting a new record for highest daily peak load of 23,753 MWs on July 20, 2011.

The changes in heating and cooling degree days in ComEd's service territory consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2011**	**2010**	**Normal**	**From 2010**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	6,134	5,991	6,362	2.4%	(3.6)%
Cooling Degree-Days	1,036	1,181	855	(12.3)%	21.2%

Uncollectible accounts recovery, net

Represents recoveries under ComEd's uncollectible accounts tariff. Refer to uncollectible accounts expense discussion below for further information.

Operating and Maintenance Expense

	Year Ended December 31,		Increase	Year Ended December 31,		Increase
	2012	**2011**	**2012 vs. 2011**	**2011**	**2010**	**2011 vs. 2010**
Operating and maintenance expense—baseline	$1,198	$1,074	$124	$1,074	$ 975	$ 99
Operating and maintenance expense—regulatory required programs (a)	147	115	32	115	94	21
Total operating and maintenance expense	$1,345	$1,189	$156	$1,189	$1,069	$120

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for year ended December 31, 2012, compared to the same period in 2011 and changes for the year ended December 31, 2011, compared to the same period in 2010, consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Baseline		
Labor, other benefits, contracting and materials [b]	$ 95	$ 72
Pension and non-pension postretirement benefits expense	46	1
Discrete impacts from 2010 Rate Case order [a]	32	(32)
Corporate Allocations	—	8
Storm Related Costs [d]	(1)	2
Technology Innovation Trust [d]	(11)	15
Uncollectible accounts expense—one-time impact of 2010 ICC Order [c]	—	60
Uncollectible accounts expense, net [c]	(27)	(33)
Other	(10)	6
	124	99
Regulatory required programs		
Energy efficiency and demand response programs	33	25
Purchased power administrative costs	(1)	(4)
	32	21
Increase in operating and maintenance expense	$156	$120

(a) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time net benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan.
(b) The increase in 2012 labor, other benefits, contracting and material costs is the result of the first year of a ten year grid modernization project associated with EIMA. See Note 3 of the Combined Notes to the Financial Statements for additional information.
(c) On February 2, 2010, the ICC issued an order adopting ComEd's proposed tariffs filed in accordance with Illinois legislation providing public utilities the ability to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually through a rider mechanism starting with 2008 and prospectively. As a result of this order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a onetime contribution of $10 million associated with this legislation.
(d) Under EIMA, ComEd may recover costs associated with certain one-time events, such as large storms, over a five-year period. During the fourth quarter of 2011, ComEd recorded a net reduction in operating and maintenance expense for costs related to three significant 2011 storms. In addition, pursuant to EIMA, ComEd makes recurring payments for contribution to a Science and Technology Innovation Trust fund that will be used to fund energy innovation.

Operating and maintenance expense for regulatory required programs

Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2012 compared to 2011 and 2011 compared to 2010, consisted of the following:

	Increase 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Depreciation expense associated with higher plant balances [a]	$22	$20
Storm Cost Amortization	4	14
Other Regulatory Asset Amortization	14	(2)
Other	16	6
Increase in depreciation and amortization expense	$56	$38

Taxes Other Than Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. Taxes other than income taxes decreased primarily due to decreased Illinois electricity distribution taxes. Taxes other than income, which can vary period to period, include municipal and state utility taxes, real estate taxes, and payroll taxes.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. Taxes other than income taxes increased primarily due to the accrual of estimated future refunds of Illinois utility distribution tax recorded in 2010 for the 2008 and 2009 tax years. Previously, ComEd had recorded refunds of the Illinois utility distribution tax when received. Due to sufficient, reliable evidence, ComEd began in June 2010 recording an estimated receivable associated with anticipated Illinois utility distribution tax refunds prospectively.

Interest Expense, Net

The changes in interest expense, net for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	(Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Interest expense related to uncertain tax positions [(a)]	$—	$(63)
Interest expense on debt (including financing trusts) [(b)]	(26)	20
Other	(12)	2
Decrease in interest expense, net	$(38)	$(41)

(a) During 2010, ComEd recorded $59 million of interest expense associated with the re-measurement of uncertain income tax positions related to the 1999 sale of Fossil Generating Assets.

(b) Interest expense on debt decreased in 2012 due to more favorable interest rates on long-term debt balances year over year.

Other, Net

The changes in other, net for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Interest income related to uncertain tax positions	$16	$ 8
Other	(6)	(3)
Increase in Other, net	$10	$ 5

Effective Income Tax Rate

ComEd's effective income tax rate for the years ended December 31, 2012, 2011, and 2010 was 38.7%, 37.5% and 51.4%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Retail Deliveries to customers (in GWhs)	2012	2011	% Change 2012 vs 2011	Weather-Normal % Change	2010	% Change 2011 vs 2010	Weather-Normal % Change
Retail Delivery and Sales [(a)]							
Residential	28,528	28,273	0.9%	(0.6)%	29,171	(3.1)%	(1.3)%
Small commercial & industrial	32,534	32,281	0.8%	0.2%	32,904	(1.9)%	(0.8)%
Large commercial & industrial	27,643	27,732	(0.3)%	(0.3)%	27,717	0.1%	0.6%
Street Lighting & electric railroads	1,272	1,235	3.0%	4.2%	1,273	(3.0)%	(1.2)%
Total Retail	89,977	89,521	0.5%	(0.1)%	91,065	(1.7)%	(0.5)%

Number of Electric Customers	As of December 31, 2012	2011	2010
Residential	3,455,546	3,448,481	3,438,677
Small commercial & industrial	365,357	365,824	363,393
Large commercial & industrial	1,980	2,032	2,005
Street Lighting & electric railroads	4,812	4,797	5,078
Total	3,827,695	3,821,134	3,809,153

Electric Revenue	2012	2011	% Change 2012 vs 2011	2010	% Change 2011 vs 2010
Retail Delivery and Sales (a)					
Residential	$3,037	$3,510	(13.5)%	$3,549	(1.1)%
Small commercial & industrial	1,339	1,517	(11.7)%	1,639	(7.4)%
Large commercial & industrial	395	383	3.1%	397	(3.5)%
Street Lighting & electric railroads	44	50	(12.0)%	62	(19.4)%
Total Retail	4,815	5,460	(11.8)%	5,647	(3.3)%
Other Revenue (b)	628	596	5.4%	557	7.0%
Total Electric Revenues	$5,443	$6,056	(10.1)%	$6,204	(2.4)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from ComEd and customers purchasing electricity from a competitive electric generation supplier. All customers are assessed charges for delivery. For customers purchasing electricity from ComEd, revenue also reflects the cost of energy and transmission.

(b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenue, revenues related to late payment charges, assistance provided to other utilities through mutual assistance programs and recoveries of environmental remediation costs associated with MGP sites.

Results of Operations—PECO

	2012	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$3,186	$3,720	$(534)	$5,519	$(1,799)
Purchased power and fuel	1,375	1,864	489	2,762	898
Revenue net of purchased power and fuel expense (a)	1,811	1,856	(45)	2,757	(901)
Other operating expenses					
Operating and maintenance	809	794	(15)	733	(61)
Depreciation and amortization	217	202	(15)	1,060	858
Taxes other than income	162	205	43	303	98
Total other operating expenses	1,188	1,201	13	2,096	895
Operating income	623	655	(32)	661	(6)
Other income and (deductions)					
Interest expense, net	(123)	(134)	11	(193)	59
Other, net	8	14	(6)	8	6
Total other income and (deductions)	(115)	(120)	5	(185)	65
Income before income taxes	508	535	(27)	476	59
Income taxes	127	146	19	152	6
Net income	381	389	(8)	324	65
Preferred security dividends	4	4	—	4	—
Net income on common stock	$ 377	$ 385	$ (8)	$ 320	$ 65

(a) PECO evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. PECO believes revenue net of purchased power expense and revenue net of fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. PECO has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power expense and revenue net of fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by lower operating revenue net of purchased power and fuel expense and increased storm costs. The decrease in revenue net of purchased power and fuel expense was primarily related to unfavorable weather and a decline in electric load. The decrease to net income was partially offset by lower taxes other than income, interest expense and income taxes.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in net income was primarily driven by new distribution rates effective January 1, 2011 as a result of the 2010 electric and natural gas rate case settlements, decreased interest expense and decreased income tax expense. The increase in net income was partially offset by increased storm costs, increased depreciation expense and the net impact of the 2010 CTC recoveries reflected in electric operating revenues net of purchased power expense and CTC amortization expense, both of which ceased at the end of the transition period on December 31, 2010.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power and fuel expense, such as commodity procurement costs and customer choice programs. PECO's electric generation rates charged to customers were capped until December 31, 2010 in accordance with the 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric generation rates are based on actual costs incurred through its approved competitive market procurement process. Electric and gas revenues and purchased power and fuel expenses are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly and are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with the PAPUC's GSA and PGC, respectively. Therefore, fluctuations in electric supply and natural gas procurement costs have no impact on electric and gas revenues net of purchased power and fuel expenses.

Electric and gas revenues and purchased power and fuel expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchase power and fuel expense. The number of retail customers purchasing energy from a competitive electric generation supplier was 496,500, 387,600 and 36,600 at December 31, 2012, 2011 and 2010, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 66%, 57% and 1% of PECO's retail kWh sales for the years ended December 31, 2012, 2011 and 2010, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 53,600, 24,800 and 6,800 at December 31, 2012, 2011 and 2010, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 16%, 11% and 7% of PECO's mmcf sales for the years ended December 31, 2012, 2011 and 2010, respectively.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Weather	$(17)	$(15)	$(32)
Volume	(22)	—	(22)
Pricing	(4)	3	(1)
Regulatory required programs	29	—	29
Other	(19)	—	(19)
Total decrease	$(33)	$(12)	$(45)

Weather

The demand for electricity and gas is affected by weather conditions. With respect to the electric business, very warm weather in summer months and, with respect to the electric and gas businesses, very cold weather in winter months are referred to as "favorable weather conditions" because these weather conditions result in increased deliveries of electricity and gas. Conversely, mild weather reduces demand. Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable winter weather conditions during 2012 in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**% Change From 2011**	**% Change From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	3,747	4,157	4,603	(9.9)%	(18.6)%
Cooling Degree-Days	1,603	1,617	1,301	(0.9)%	23.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected the reduced oil refinery load in PECO's service territory and the impact of energy efficiency initiatives and weak economic conditions on customer usage. The decrease was partially offset by additional volumes due to the extra day from the leap year. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

Pricing

The decrease in operating revenues net of purchased power and fuel expense as a result of pricing reflects the refund of the tax cash benefit resulting from the adoption of the safe harbor method of tax accounting for electric distribution property in 2011. The refund was reflected on customer bills as a credit beginning January 1, 2012. The accounting impact of the refund is completely offset by regulatory liability amortization recorded in income tax expense. The decrease in operating revenues net of purchase power and fuel expense as a result of pricing was partially offset by higher overall effective rates due to decreased usage per customer across all customer classes.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected a decrease in GRT revenue as a result of lower supplied energy service and a reduction in the GRT rate. There is an equal and offsetting decrease in GRT expense included in taxes other than income.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2011 compared to the same period in 2010 consisted of the following:

	Increase (Decrease) Electric	**Gas**	**Total**
Weather	$ (33)	$(13)	$ (46)
Volume	(11)	3	(8)
CTC recoveries	(995)	—	(995)
Pricing	139	16	155
Regulatory required programs	17	—	17
Other	(29)	5	(24)
Total increase (decrease)	$(912)	$ 11	$(901)

Weather

Electric and gas revenues net of purchased power and fuel expense were lower due to unfavorable weather conditions during 2011 in PECO's service territory compared to 2010 despite setting a new record for highest electric peak load of 8,983 MWs on July 22, 2011.

The changes in heating and cooling degree days for the twelve months ended 2011 and 2010, consisted of the following:

				% Change	
Heating and Cooling Degree-Days [(a)]	**2011**	**2010**	**Normal**	**From 2010**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	4,157	4,396	4,638	(5.4)%	(10.4)%
Cooling Degree-Days	1,617	1,817	1,292	(11.0)%	25.2%

Volume

The decrease in electric revenues net of purchased power expense related to delivery volume, exclusive of the effects of weather, reflected weak economic growth, the impact of energy efficiency initiatives on customer usage and the ramp-down of two oil refineries. See Note 3 of the Combined Notes to the Consolidated Financial Statements for further information regarding energy efficiency initiatives.

The increase in gas revenues net of fuel expense related to delivery volume, exclusive of the effects of weather, reflected increased usage per customer across all customer classes.

CTC Recoveries

The decrease in electric revenues net of purchased power expense related to CTC recoveries reflected the absence of the CTC charge component that was included in rates charged to customers in 2010. PECO fully recovered all stranded costs during the final year of the transition period that expired on December 31, 2010.

Pricing

The increase in operating revenues net of purchased power and fuel expense as a result of pricing primarily reflected an increase of new electric and natural gas distribution rates charged to customers that became effective in January 1, 2011 in accordance with the 2010 PAPUC approved electric and natural gas distribution rate case settlements. See Note 3 of the Combined Notes to the Consolidated Financial Statements for further information.

Regulatory Required Programs

This represents the change in operating revenues collected under approved riders to recover costs incurred for the smart meter, energy efficiency and consumer education programs as well as the administrative costs for the GSA and AEPS programs. The riders are designed to provide full and current cost recovery as well as a return. The offsetting costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and income taxes. Refer to the operating and maintenance expense discussion below for additional information on included programs.

Other

The decrease in electric revenues net of purchased power expense primarily reflected a decrease in GRT revenue as a result of lower supplied energy service and retail transmission revenue earned by PECO due to increased participation in the customer choice program. There is an equal and offsetting decrease in GRT expense included in taxes other than income. This decrease was partially offset by an increase in wholesale transmission revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM. The rates charged for wholesale transmission are based on the prior year's peak, and the peak in 2010 was higher than in 2009.

The increase in gas operating revenues net of fuel expense primarily reflected an increase in off-system gas sales activity. Off-system gas sales revenues represent sales of excess gas supply on the wholesale market and the release of pipeline capacity.

Operating and Maintenance Expense

	Twelve Months Ended December 31,		Increase (Decrease)	Twelve Months Ended December 31,		Increase (Decrease)
	2012	2011	2012 vs. 2011	2011	2010	2011 vs. 2010
Operating and Maintenance Expense—Baseline	$723	$725	$ (2)	$725	$680	$45
Operating and Maintenance Expense—Regulatory Required Programs [(a)]	86	69	17	69	53	16
Total Operating and Maintenance Expense	$809	$794	$15	$794	$733	$61

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Baseline		
Labor, other benefits, contracting and materials	$(29)	$26
Storm-related costs	9 [(a)]	13
Uncollectible accounts expense	(4)	4
Constellation merger and integration costs	15	2
2010 non-cash charge resulting from Health Care Legislation	—	(2)
Other	7	2
	(2)	45
Regulatory Required Programs		
Smart Meter	12	9
Energy Efficiency	8	2
GSA	(1)	5
Consumer education program	(1)	(1)
AEPS	(1)	1
	17	16
Increase in operating and maintenance expense	$ 15	$61

(a) Storm-related costs include $46 million of incremental storm costs incurred in the fourth quarter of 2012 as a result of Hurricane Sandy. This expense was significantly offset by the costs incurred related to Hurricane Irene and other storms throughout 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
CTC amortization [(a)]	$—	$(885)
Other [(b)]	15	27
Increase (decrease) in depreciation and amortization expense	$ 15	$(858)

(a) PECO's scheduled CTC amortization was recorded in accordance with its 1998 restructuring settlement and was fully amortized as of December 31, 2010.
(b) Increase due primarily to ongoing capital expenditures.

Taxes Other Than Income

The change in taxes other than income for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
GRT expense [(a)]	$(33)	$(97)
Sales and use tax	(12)[(b)]	—
PURTA amortization	—	(4)[(c)]
Other	2	3
Decrease in taxes other than income	$(43)	$(98)

(a) The decrease in GRT expense for 2012 compared to 2011 and 2011 compared to 2010 was a result of lower operating revenues. In addition, there was a reduction in the GRT rate in 2012.
(b) The decrease reflects a sales and use tax reserve adjustment in the first quarter of 2012 resulting from the completion of the audit of tax years 2005 through 2010.
(c) The decrease in taxes other than income related to PURTA amortization reflects the impact of regulatory liability amortization recorded in 2011 that offsets the distribution rate reduction made to refund a 2009 PURTA Supplemental Tax settlement to customers.

Interest Expense, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in interest expense, net for 2012 compared to 2011 was primarily due to the debt retirement in November 2011.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The decrease in interest expense, net for 2011 compared to 2010 was primarily due to the retirement of PETT transition bonds on September 1, 2010 and the impact of interest expense incurred in June 2010 related to the change in measurement of uncertain tax positions in accordance with accounting guidance.

See Notes 1 and 12 of the Combined Notes to Consolidated Financial Statements for further information.

Other, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in Other, net for 2012 compared to 2011 was due to decreased AFUDC—Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements for additional details of the components of Other, net.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in Other, net for 2011 compared to 2010 was primarily due to increased investment income and AFUDC Equity. See Note 20 of the Combined Notes to Consolidated Financial Statements for further information.

Effective Income Tax Rate

PECO's effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 25.0%, 27.3% and 31.9%, respectively. The effective income tax rate for the year ended December 31, 2012 reflects the impact of the tax benefit received from electing to change the method of accounting for gas distribution property for the 2011 tax year. Comparatively, the effective income tax rate for the year ended December 31, 2011 includes the effect of electing the safe harbor method of tax accounting for electric distribution property for the 2010 tax year. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [(a)]							
Residential	13,233	13,687	(3.3)%	(1.7)%	13,913	(1.6)%	1.7%
Small commercial & industrial	8,063	8,321	(3.1)%	(2.3)%	8,503	(2.1)%	(0.7)%
Large commercial & industrial	15,253	15,677	(2.7)%	(2.7)%	16,372	(4.2)%	(3.3)%
Public authorities & electric railroads	943	945	(0.2)%	(0.2)%	925	2.2%	4.6%
Total Electric Retail	37,492	38,630	(2.9)%	(2.2)%	39,713	(2.7)%	(0.9)%

Number of Electric Customers	As of December 31, 2012	2011	2010
Residential	1,417,773	1,415,681	1,411,643
Small commercial & industrial	148,803	148,570	148,297
Large commercial & industrial	3,111	3,110	3,071
Public authorities & electric railroads	9,660	9,689	9,670
Total	1,579,347	1,577,050	1,572,681

Electric Revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [(a)]					
Residential	$1,689	$1,934	(12.7)%	$2,069	(6.5)%
Small commercial & industrial	462	585	(21.0)%	1,061	(44.9)%
Large commercial & industrial	232	308	(24.7)%	1,364	(77.4)%
Public authorities & electric railroads	31	38	(18.4)%	89	(57.3)%
Total Retail	2,414	2,865	(15.7)%	4,583	(37.5)%
Other Revenue [(b)]	226	244	(7.4)%	252	(3.2)%
Total Electric Revenues	$2,640	$3,109	(15.1)%	$4,835	(35.7)%

(a) Reflects delivery volumes and revenues from customers purchasing electricity directly from PECO and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from PECO, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes transmission revenue from PJM and wholesale electric revenues.

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [(b)]							
Retail sales	49,767	54,239	(8.2)%	(0.1)%	56,833	(4.6)%	1.2%
Transportation and other	26,687	28,204	(5.4)%	(4.8)%	30,911	(8.8)%	(7.5)%
Total Gas Deliveries	76,454	82,443	(7.3)%	(1.6)%	87,744	(6.0)%	(1.8)%

Number of Gas Customers	As of December 31, 2012	2011	2010
Residential	454,502	451,382	448,391
Commercial & industrial	41,836	41,373	41,303
Total Retail	496,338	492,755	489,694
Transportation	903	879	838
Total	497,241	493,634	490,532

Gas revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [(a)]					
Retail sales	$509	$576	(11.6)%	$657	(12.3)%
Transportation and other	37	35	5.7%	27	29.6%
Total Gas Deliveries	$546	$611	(10.6)%	$684	(10.7)%

(a) Reflects delivery volumes and revenues from customers purchasing natural gas directly from PECO and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. For customers purchasing natural gas from PECO, revenue also reflects the cost of natural gas.

Results of Operations—BGE

	2012	2011	Favorable (unfavorable) 2012 vs. 2011 variance	2010	Favorable (unfavorable) 2011 vs. 2010 variance
Operating revenues	$2,735	$3,068	$(333)	$3,541	$(473)
Purchased power and fuel expense	1,369	1,593	224	2,147	554
Revenue net of purchased power and fuel expense [(a)]	1,366	1,475	(109)	1,394	81
Other operating expenses					
Operating and maintenance	728	680	(48)	595	(85)
Depreciation and amortization	298	274	(24)	249	(25)
Taxes other than income	208	207	(1)	200	(7)
Total other operating expenses	1,234	1,161	(73)	1,044	(117)
Operating income	132	314	(182)	350	(36)
Other income and (deductions)					
Interest expense, net	(144)	(129)	(15)	(131)	2
Other, net	23	26	(3)	25	1
Total other income and (deductions)	(121)	(103)	(18)	(106)	3
Income before income taxes	11	211	(200)	244	(33)
Income taxes	7	75	68	97	22
Net income	4	136	(132)	147	(11)
Preference stock dividends	13	13	—	13	—
Net (loss) income on common stock	$ (9)	$ 123	$(132)	$ 134	$ (11)

(a) BGE evaluates its operating performance using the measures of revenue net of purchased power expense for electric sales and revenue net of fuel expense for gas sales. BGE believes revenue net of purchased power and fuel expense are useful measurements of its performance because they provide information that can be used to evaluate its net revenue from operations. BGE has included the analysis below as a complement to the financial information provided in accordance with GAAP. However, revenue net of purchased power and fuel expense figures are not a presentation defined under GAAP and may not be comparable to other companies' presentations or more useful than the GAAP information provided elsewhere in this report.

Net Income

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The decrease in net income was driven primarily by decreased operating revenue net of purchased power and fuel expense related to the residential customer rate credit provided as a condition of the MDPSC's approval of Exelon's merger with Constellation. The decrease in net income was also driven by increased operating and maintenance expenses, primarily related to BGE's accrual of its portion of the charitable contributions to be provided as a condition of the MDPSC's approval of the merger as well as merger transaction costs, and increased depreciation and amortization expense. None of the customer rate credit, the charitable contributions, or the transaction costs are recoverable from BGE's customers.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The decrease in net income was primarily driven by increased storm costs, increased depreciation and amortization expense and increased merger transaction costs. Partially offsetting these unfavorable impacts were increased operating revenues primarily driven by new distribution rates as a result of the 2010 Maryland PSC rate order. None of the transaction costs are recoverable from BGE's customers.

Operating Revenues Net of Purchased Power and Fuel Expense

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenues and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive EGS affects electric SOS revenues and purchased power expense. The number of customers electing to select a competitive NGS affects gas cost adjustment revenues and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive EGS. This customer choice of EGSs does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive EGS was 362,000, 314,000 and 228,000 at December 31, 2012, 2011 and 2010, respectively, representing 29%, 25% and 18% of total retail customers, respectively. Retail deliveries purchased from competitive EGSs represented 60%, 58% and 50% of BGE's retail kWh sales for the years ended December 31, 2012, 2011 and 2010, respectively. The number of retail customers purchasing natural gas from a competitive NGS was 143,000, 118,000 and 84,000 at December 31, 2012, 2011 and 2010, respectively, representing 22%, 18% and 13% of total retail customers, respectively. Retail deliveries purchased from competitive NGSs represented 56%, 52% and 49% of BGE's retail mmcf sales for the years ended December 31, 2012, 2011 and 2010, respectively.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2012 compared to the same period in 2011 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Residential customer rate credit [(a)]	$(82)	$(31)	$(113)
Commodity margin	(1)	(5)	(6)
Regulatory program cost recovery	15	4	19
Transmission	11	—	11
Other	(13)	(7)	(20)
Total decrease	$(70)	$(39)	$(109)

(a) In accordance with the MDPSC order approving Exelon's merger with Constellation, the residential customer rate credit is not recoverable from BGE's customers. Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

Revenue Decoupling. 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 allows BGE to recognize revenues at MDPSC-approved levels per customer, regardless of what BGE's actual distribution volumes were for a billing period. 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.

Volume. Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the year ended December 31, 2012 compared to the same period in 2011 and normal weather consisted of the following:

				% Change	
Heating and Cooling Degree-Days	**2012**	**2011**	**Normal**	**From 2011**	**From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	3,960	4,326	4,711	(8.5)%	(15.9)%
Cooling Degree-Days	1,022	1,035	858	(1.3)%	19.1%

Residential Customer Rate Credit

The residential customer rate credit provided as a result of the MDPSC's order approving Exelon's merger with Constellation decreased operating revenues net of purchased power and fuel expense for year ended December 31, 2012.

Commodity Margin

The commodity margin for both electric and gas revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Commodity revenues are affected by the number of customers using competitive suppliers as well as the cost of purchased power and natural gas.

Regulatory Required Programs

This represents the change in revenues collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The increase in revenues during the year ended December 31, 2012 compared to the same period in 2011 was due to the recovery of higher energy efficiency program costs.

Transmission

Transmission revenues increased during the year ended December 31, 2012 compared to the same period in 2011. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues decreased during the year ended December 31, 2012 compared to the same period in 2011. Other revenues, which can vary from period to period, include miscellaneous revenues such as late payment charge revenues and all base distribution revenues, including the impact of revenue decoupling, which decreased due to lower volumes and customer mix.

The changes in BGE's operating revenues net of purchased power and fuel expense for the year ended December 31, 2011 compared to the same period in 2010 consisted of the following:

	Increase (Decrease)		
	Electric	**Gas**	**Total**
Distribution rates increase	$ 28	$ 8	$ 36
Commodity margin	(17)	2	(15)
Regulatory program cost recovery	20	1	21
Transmission	18	—	18
Other	16	5	21
Total increase	$ 65	$ 16	$ 81

Volume

The changes in heating and cooling degree days for the twelve months ended 2011 and 2010, consisted of the following:

Heating and Cooling Degree-Days [(a)]	**2011**	**2010**	**Normal**	**% Change From 2010**	**% Change From Normal**
Twelve Months Ended December 31,					
Heating Degree-Days	4,326	4,716	4,720	(8.3)%	(8.3)%
Cooling Degree-Days	1,035	1,122	853	(7.8)%	21.3%

Distribution Rates Increase

The MDPSC issued an order approving an increase in BGE's annual electric distribution revenue requirement. The order became effective December 4, 2010, resulting in higher revenues for the year ended December 31, 2011 compared to the same period in 2010. See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.

Commodity Margin

The commodity margin for electric revenues decreased during the year ended December 31, 2011 compared to the same period in 2010. Commodity revenues are affected by the number of customers using competitive suppliers as well as the cost of purchased power and natural gas. Additionally, the decrease is a result of the reinstatement of the credit for the residential return component of the administrative charge on June 1, 2010. This credit will continue through December 2016.

Regulatory Program Cost Recovery

The increase in electric revenues relating to regulatory program cost recovery was due to the recovery of higher energy efficiency program costs and demand response program costs. The costs of these programs are recoverable from customers on a full and current basis through approved regulated rates and have been reflected in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes.

Transmission

Transmission revenues increased during the year ended December 31, 2011 compared to the same period in 2010. BGE's transmission rates are established based on a FERC-approved formula. The rates also include transmission investment incentives approved by FERC in a number of orders covering various new transmission investment projects since 2007.

Other

Other revenues increased during the year ended December 31, 2011 compared to the same period in 2010. Other revenues, which can vary from period to period, include miscellaneous revenues such as late payment charge revenues and all other base distribution revenues, including the impact of revenue decoupling, which increased due to higher volumes and customer mix.

Operating and Maintenance Expense

	Twelve Months Ended December 31,		Increase (Decrease)	Twelve Months Ended December 31,		Increase (Decrease)
	2012	2011	2012 vs. 2011	2011	2010	2011 vs. 2010
Operating and Maintenance Expense—Baseline	$728	$679	$49	$679	$591	$88
Operating and Maintenance Expense—Regulatory Required Programs [(a)]	—	1	(1)	1	4	(3)
Total Operating and Maintenance Expense	$728	$680	$48	$680	$595	$85

(a) Operating and maintenance expenses for regulatory required programs are costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through approved regulated rates. An equal and offsetting amount has been reflected in operating revenues.

The changes in operating and maintenance expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Baseline		
Charitable contributions [(a)]	$ 28	$—
Storm costs deferral [(b)]	16	(16)
Storm-related costs [(c)]	7	41
Pension and non-pension postretirement benefits expense	6	2
Labor, other benefits, contracting and materials	(10)	25
Merger transaction costs [(a)]	(9)	30
Uncollectible accounts expense	—	6
Other	11	—
	49	88
Regulatory Required Programs		
SOS	(1)	(3)
	(1)	(3)
Increase in operating and maintenance expense	$ 48	$ 85

(a) The charitable contribution accrual and merger transaction costs are not recoverable from BGE's customers.
(b) During the first quarter of 2011, the MDPSC issued a comprehensive rate order permitting the deferral of incremental distribution service restoration expenses associated with 2010 storms as a regulatory asset.
(c) On June 29, 2012, a "Derecho" storm caused extensive damage to BGE's electric distribution system and created power outages that lasted multiple days. As a result, BGE incurred $62 million of incremental costs during the year ended December 31, 2012, of which $20 million are capital costs. In the fourth quarter of 2012, BGE incurred $38 million of incremental costs as a result of Hurricane Sandy, of which $14 million are capital costs. These amounts compare to $40 million of incremental expenses incurred during the third quarter of 2011 associated with Hurricane Irene and $14 million of incremental expenses incurred during the first quarter of 2011.

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Depreciation expense [(a)]	$20	$10
Regulatory asset amortization	6	13
Other	(2)	2
Increase in depreciation and amortization expense	$24	$25

(a) Depreciation and amortization expense increased due to higher plant balances year over year.

Taxes Other Than Income

The change in taxes other than income for 2012 compared to 2011 and 2011 compared to 2010 consisted of the following:

	Increase (Decrease) 2012 vs. 2011	Increase (Decrease) 2011 vs. 2010
Property tax	$ 4	$5
Other	(3)	2
Increase in taxes other than income	$ 1	$7

Interest Expense, Net

Year Ended December 31, 2012 Compared to Year Ended December 31, 2011. The increase in interest expense, net for 2012 compared to 2011 was primarily due to higher outstanding debt balances.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The change in interest expense, net in 2011 compared to 2010 was relatively flat.

Effective Income Tax Rate

BGE's effective income tax rates for the years ended December 31, 2012, 2011 and 2010 were 63.6%, 35.5% and 39.8%, respectively. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [(a)]							
Residential	12,719	12,652	0.5%	n.m.	13,834	(8.5)%	n.m.
Small commercial & industrial	15,943	16,276	(2.0)%	n.m.	16,040	1.5%	n.m.
Large commercial & industrial	1,980	2,464	(19.6)%	n.m.	2,578	(4.4)%	n.m.
Public authorities & electric railroads	329	405	(18.8)%	n.m.	400	1.3%	n.m.
Total Electric Retail	30,971	31,797	(2.6)%	n.m.	32,852	(3.2)%	n.m.

	As of December 31,		
Number of Electric Customers	**2012**	**2011**	**2010**
Residential	1,116,233	1,116,401	1,114,712
Small commercial & industrial	119,122	118,568	118,250
Large commercial & industrial	5,452	5,823	5,534
Public authorities & electric railroads	319	326	326
Total	1,241,126	1,241,118	1,238,822

Electric Revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [(a)]					
Residential	$1,274	$1,456	(12.5)%	$1,857	(21.6)%
Small commercial & industrial	600	632	(5.1)%	687	(8.0)%
Large commercial & industrial	40	51	(21.6)%	53	(3.8)%
Public authorities & electric railroads	30	29	3.4%	30	(3.3)%
Total Retail	1,944	2,168	(10.3)%	2,627	(17.5)%
Other Revenue [(b)]	239	228	4.8%	204	11.8%
Total Electric Revenues	$2,183	$2,396	(8.9)%	$2,831	(15.4)%

(a) Reflects delivery revenues and volumes from customers purchasing electricity directly from BGE and customers purchasing electricity from a competitive electric generation supplier as all customers are assessed distribution charges. For customers purchasing electricity from BGE, revenue also reflects the cost of energy and transmission.

(b) Other revenue includes wholesale transmission revenue and late payment charges.

BGE Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2012	2011	% Change 2012 vs. 2011	Weather-Normal % Change	2010	% Change 2011 vs. 2010	Weather-Normal % Change
Retail Delivery and Sales [c]							
Retail sales	86,946	94,800	(8.3)%	n.m.	98,928	(4.2)%	n.m.
Transportation and other [d]	15,751	16,436	(4.2)%	n.m.	14,711	11.7%	n.m.
Total Gas Deliveries	102,697	111,236	(7.7)%	n.m.	113,639	(2.1)%	n.m.

Number of Gas Customers	As of December 31, 2012	2011	2010
Residential	610,827	608,943	608,553
Commercial & industrial	44,228	44,211	44,041
Total	655,055	653,154	652,594

Gas revenue	2012	2011	% Change 2012 vs. 2011	2010	% Change 2011 vs. 2010
Retail Delivery and Sales [c]					
Retail sales	$494	$580	(14.8)%	$620	(6.5)%
Transportation and other [d]	58	92	(37.0)%	90	2.2%
Total Gas Deliveries	$552	$672	(17.9)%	$710	(5.4)%

(c) Reflects delivery revenues and volumes from customers purchasing natural gas directly from BGE and customers purchasing natural gas from a competitive natural gas supplier as all customers are assessed distribution charges. The cost of natural gas is charged to customers purchasing natural gas from BGE.

(d) Transportation and other gas revenue includes off-system revenue of 15,751 mmcfs ($51 million), 16,436 mmcfs ($82 million) and 14,711 mmcfs ($80 million) for the years ended 2012, 2011 and 2010, respectively.

Liquidity and Capital Resources

Exelon and Generation activity presented below includes the activity of Constellation, and BGE in the case of Exelon, from the merger effective date of March 12, 2012 through December 31, 2012. Exelon and Generation activity for 2011 and 2010 is unadjusted for the effects of the merger. BGE activity presented below includes its activity for the 12 months ended December 31, 2012, 2011 and 2010.

Exelon's operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. Exelon's businesses are capital intensive and require considerable capital resources. Each Registrant's access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion, $0.6 billion and $0.6 billion, respectively. The Registrants' revolving credit facilities are in place until 2017. In addition, Generation has a $0.3 billion bilateral facility with a bank. The bilateral facility at Generation has expirations in December 2015 and March 2016. Exelon utilizes its credit facilities to support its commercial paper programs, provide for other short-term borrowings and to issue letters of credit. See the "Credit Matters" section below for further discussion. Exelon expects cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon primarily uses its capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. Exelon spends a significant amount of cash on capital improvements and construction projects that have a long-term return on investment. Additionally, ComEd, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 11 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers. ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions. See Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements for further discussion of regulatory and legal proceedings and proposed legislation.

Pension and Other Postretirement Benefits

Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006, management of the pension obligation and regulatory implications. Exelon expects to contribute approximately $270 million to its pension plans in 2013, of which Generation, ComEd, PECO and BGE expect to contribute $119 million, $117 million, $12 million and $2 million, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2012 and 2011 pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued recovery). Exelon expects to contribute approximately $292 million to the other postretirement benefit plans in 2013, of which Generation, ComEd, PECO and BGE expect to contribute $117 million, $114 million, $22 million and $18 million, respectively. See Note 14 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2012 and 2011 other postretirement benefit contributions.

See the "Contractual Obligations" section below for management's estimated future pension and other postretirement benefits contributions.

Tax Matters

Exelon's future cash flows from operating activities may be affected by the following tax matters:

- In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon's involuntary conversion and CTC positions. Exelon expects that the IRS will assess approximately $300 million of tax and interest in the first quarter of 2013. In order to stop additional interest from accruing on the expected assessment, Exelon had previously made a payment in December 2010 to the IRS of $302 million. In addition Exelon, Generation, ComEd and PECO expect to receive tax refunds of approximately $375 million, $50 million, $350 million and $25 million, respectively, between 2013 and 2014, and the remainder paid by Exelon.
- Given the current economic environment, state and local governments are facing increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes.
- In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The newly adopted method results in a cash tax benefit of approximately $38 million and $41 million at Exelon and PECO, respectively. Exelon currently anticipates that the IRS will issue industry guidance during 2013. See Note 3 of the Combined Notes to Consolidated Financial Statements for discussion regarding the regulatory treatment of PECO's tax benefits from the application of the method change.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the years ended December 31, 2012, 2011 and 2010:

	2012	2011	2012 vs. 2011 Variance	2010	2011 vs. 2010 Variance
Net income	$1,171	$ 2,499	$(1,328)	$2,563	$ (64)
Add (subtract):					
Non-cash operating activities [(a)]	5,588	4,848	740	4,340	508
Pension and non-pension postretirement benefit contributions	(462)	(2,360)	1,898	(959)	(1,401)
Income taxes	544	492	52	(543)	1,035
Changes in working capital and other noncurrent assets and liabilities [(b)]	(731)	(279)	(452)	122	(401)
Option premiums paid, net	(114)	(3)	(111)	(124)	121
Counterparty collateral received (paid), net	135	(344)	479	(155)	(189)
Net cash flows provided by operations	$6,131	$ 4,853	$ 1,278	$5,244	$ (391)

(a) Represents depreciation, amortization and accretion, mark-to-market gains and losses on derivative transactions, deferred income taxes, provision for uncollectible accounts, pension and non-pension postretirement benefit expense, equity in earnings and losses of unconsolidated affiliates and investments, decommissioning-related items, stock compensation expense, impairment of long-lived assets, and other non-cash charges.

(b) Changes in working capital and other noncurrent assets and liabilities exclude the changes in commercial paper, income taxes and the current portion of long-term debt.

Cash flows provided by operations for 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon	$6,131	$4,853	$5,244
Generation	3,581	3,313	3,032
ComEd	1,334	836	1,077
PECO	878	818	1,150
BGE	485	476	329

Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business. In addition, significant operating cash flow impacts for the Registrants for 2012, 2011 and 2010 were as follows:

Generation

- During 2012, 2011 and 2010, Generation had net (payments) receipts of counterparty collateral of $95 million, $(410) million and $(1) million, respectively. Net payments during 2012 and 2011 were primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. This collateral may be in various forms, such as cash, which may be obtained through the issuance of commercial paper, or letters of credit.
- During 2007, Generation, along with ComEd and other generators and utilities, reached an agreement with various representatives from the State of Illinois to address concerns about higher electric bills in Illinois. Generation committed to contributing approximately $747 million over four years. As part of the agreement, Generation contributed cash of approximately $23 million in 2010. As of December 31, 2010, Generation had fulfilled its commitments under the Illinois Settlement Legislation.
- During 2012, 2011 and 2010, Generation's accounts receivable from ComEd increased (decreased) by $(15) million, $12 million and $(65) million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC-approved RFP contracts and financial swap contract.
- During 2012, 2011 and 2010, Generation's accounts receivable from PECO increased (decreased) by $17 million, $(210) million and $74 million, respectively.
- During 2012, 2011 and 2010, Generation had net payments of approximately $114 million, $3 million and $124 million, respectively, related to purchases and sales of options. The level of option activity in a given year may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

ComEd

- During 2012, 2011 and 2010, ComEd's net payables to Generation for energy purchases related to its supplier forward contract, ICC-approved RFP contracts and financial swap contract settlements increased (decreased) by $(15) million, $12 million and $(65) million, respectively. During 2012, 2011 and 2010, ComEd's payables to other energy suppliers for energy purchases increased (decreased) by $20 million, $(43) million and $58 million, respectively.
- During 2012 and 2011, ComEd received $37 million and $63 million, respectively, of incremental cash collateral from PJM due to variations in its energy transmission activity levels. As of December 31, 2012 and December 31, 2011, ComEd had $53 million and $90 million of cash collateral remaining at PJM.

PECO

- During 2012, 2011 and 2010, PECO's payables to Generation for energy purchases increased (decreased) by $17 million, $(210) million and $74 million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $(22) million, $97 million and $1 million, respectively.

BGE

- During 2012, 2011 and 2010, BGE's payables to Generation for energy purchases increased (decreased) by $23 million, $(13) million and $0 million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $40 million, $(60) million and $54 million, respectively. BGE's increase in payables to other energy suppliers in 2010 is due to the implementation of the POR program during July 2010. The decrease in payables to other energy suppliers in 2011 is due to full payment to POR suppliers due to the implementation of a new customer billing system during January 2012.

Cash Flows from Investing Activities

Cash flows used in investing activities for 2012, 2011, and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon [(a)(b)(d)]	$(4,576)	$(4,603)	$(3,894)
Generation [(a)(d)]	(2,629)	(3,077)	(2,896)
ComEd	(1,212)	(1,007)	(939)
PECO [(b)]	(328)	(557)	(120)
BGE	(573)	(592)	(177)

Capital expenditures by Registrant for 2012, 2011 and 2010 and projected amounts for 2013 are as follows:

	Projected 2013 [(c)]	2012	2011	2010
Generation [(d)]	$2,850	$3,554	$2,491	$1,883
ComEd [(e)]	1,400	1,246	1,028	962
PECO	569	422	481	545
BGE	663	582	592	508
Other [(f)]	43	67	42	(64)
Total capital expenditures	$5,525	$5,871	$4,634	$3,834

(a) Includes $387 million in 2011 related to acquisitions, principally acquisition of Wolf Hollow, Antelope Valley and Shooting Star; and $893 million in 2010, related to the acquisition of Exelon Wind. See Note 4 of the Combined Notes to Consolidated Financial Statements for additional information.

(b) Includes a cash inflow of $413 million in 2010 as a result of the consolidation of PETT on January 1, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for additional information.

(c) Total projected capital expenditures do not include adjustments for non-cash activity.

(d) Includes nuclear fuel.

(e) The projected capital expenditures include approximately $227 million of expected incremental spending. Pursuant to EIMA, ComEd has committed to invest approximately $2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology. ComEd expects to file an updated investment plan with the ICC in April, 2013.

(f) Other primarily consists of corporate operations and BSC. The negative capital expenditures for Other in 2010 primarily relate to the transfer of information technology hardware and software assets from BSC to Generation, ComEd and PECO.

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

Generation

Approximately 35% and 20% of the projected 2013 capital expenditures at Generation are for the acquisition of nuclear fuel; and investments in renewable energy generation, including Antelope Valley construction costs, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Also included in the projected 2013 capital expenditures are a portion of the costs of a series of planned power uprates across Generation's nuclear fleet. See "EXELON CORPORATION—Executive Overview," for more information on nuclear uprates.

On November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets to Raven Power Holdings LLC, a subsidiary of Riverstone Holdings LLC, and received net proceeds of approximately $371 million in the fourth quarter. In addition, Generation will make cash payments of approximately $32 million to Raven Power Holdings LLC over a twelve-month period beginning in June 2013. In 2012, Generation incurred transaction costs of approximately $15 million through the date of closing of the transaction. The sale will generate approximately $195 million of cash tax benefits, of which $155 million will be realized in periods through 2014 with the balance to be received in later years. Therefore, Generation expects net after-tax cash sale proceeds of approximately $495 million through 2014 and approximately $36 million in subsequent years.

ComEd, PECO and BGE

Approximately 89%, 89% and 77% of the projected 2013 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. In addition, this includes for ComEd capital expenditures related to smart grid/smart meter technology required under EIMA and for PECO and BGE capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. The remaining amounts are for capital additions to support new business and customer growth. See Notes 3 and 6 of the Combined Notes to Consolidated Financial Statements for additional information.

As a result of the October 3, 2012 ICC Rehearing Order, ComEd currently plans to defer approximately $400 million of smart meter and other infrastructure spend from the period beginning 2012 through 2014 to 2015 and beyond. ComEd's deferred approximately $65 million of planned spend in 2012.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines, with the highest priority lines assessed by December 31, 2011, medium priority lines by December 31, 2012, and the lowest priority lines by December 31, 2013. In compliance with this guidance, ComEd, PECO and BGE submitted their most recent bi-annual reports to NERC in January 2013. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2013 capital expenditures above reflect capital spending for remediation to be completed in 2013.

ComEd, PECO and BGE anticipate that they will fund capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 3 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon	$(1,085)	$(846)	$(1,748)
Generation	(777)	(196)	(779)
ComEd	(212)	355	(179)
PECO	(382)	(589)	(811)
BGE	128	115	(116)

Debt. Debt activity for 2012, 2011 and 2010 by Registrant was as follows:

Company	Issuances of long-term debt in 2012	Use of proceeds
Generation	$78 million of variable rate CEU Credit Agreement project financing, due July 16, 2016	Used to fund Upstream gas activities
Generation	$220 million of fixed rate DOE Project Financing, due January 5, 2037	Used for Antelope Valley solar development
Generation	$523 million of 4.25% Senior Notes due June 15, 2022	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$788 million of 5.60% Senior Notes due June 15, 2042	Used for general corporate purposes and issued in connection with the Exchange Offer
Generation	$38 million of variable rate Clean Horizons project financing due June 7, 2030	Used for funding for Maryland solar development
ComEd	$350 million of First Mortgage 3.80% Bonds, Series 113, due October 1, 2042	Used to repay outstanding commercial paper obligations and for general corporate purposes.
PECO	$350 million of First and Refunding Mortgage 2.38% Bonds due September 15, 2022	Used to pay at maturity First Mortgage Bonds due October 1, 2012 and for general corporate purposes
BGE	$250 million of fixed rate 2.80% Notes due August 15, 2022	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2011	Use of proceeds
ComEd	$600 million of First Mortgage 1.625% Bonds, Series 110, due January 15, 2014	Used as an interim source of liquidity for a January 2011 contribution to Exelon-sponsored pension plans.
ComEd	$250 million of First Mortgage 1.95% Bonds, Series 111, due September 1, 2016	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes.
ComEd	$350 million of First Mortgage 3.40% Bonds, Series 112, due September 1, 2021	Used to retire $191 million tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, E, and F, $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes.
BGE	$300 million of fixed rate 3.50% Notes, due November 15, 2021	Used to repay total outstanding commercial paper obligations and for general corporate purposes

Company	Issuances of long-term debt in 2010	Use of proceeds
Generation	$900 million of Senior Notes, consisting of $550 million Senior Notes, 4.00% due October 1, 2020 and $350 million Senior Notes, 5.75% due October 1, 2041	Used to finance the acquisition of Exelon Wind and for general corporate purposes.
ComEd	$500 million of First Mortgage Bonds at 4.00% due August 1, 2020	Used to refinance First Mortgage Bonds, Series 102, which matured on August 15, 2010 and for other general corporate purposes.

Company	Retirement of long-term debt in 2012
Exelon	$2 million of 7.30% fixed-rate Medium Term Notes with a maturity date of June 1, 2012.
Exelon	$442 million of 7.60% fixed-rate Senior Notes with a maturity date of April 1, 2032.
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$46 million of 3-year term rate Armstrong Co. 2009 A, Pollution Control Notes at 5.00% with a final maturity of December 1, 2042.
Generation	$89 million of variable rate project financing CEU Credit Agreement with a final maturity of July 16, 2016.
Generation	$17 million of variable rate Solar Revolver project financing with a final maturity of July 7, 2014.
Generation	$75 million of variable rate MEDCO tax-exempt bonds with a final maturity of April 1, 2024.
Generation	$2 million of variable rate Sacramento Solar Promissory Note with a final maturity of March 12, 2012.
ComEd	$450 million of 6.15% First Mortgage Bonds, Series 98, due March 15, 2012
PECO	$225 million of 4.75% First and Refunding Mortgage Bonds, due October 1, 2012
PECO	$150 million of 4.00% First and Refunding Mortgage Bonds, due December 1, 2012
BGE	$8 million of 5.72% fixed rate Rate Stabilization Bonds, due April 1, 2016
BGE	$55 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
BGE	$110 million of variable rate Medium Term Notes, due June 15, 2012
Generation	$2 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$2 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 D, due March 1, 2020
ComEd	$50 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 E, due May 1, 2021
ComEd	$91 million of tax-exempt variable-rate First Mortgage Bonds, Series 2008 F, due March 1, 2017
ComEd	$345 million of 5.40% First Mortgage Bonds, Series 105, due December 15, 2011
PECO	$250 million of 5.95% First and Refunding Mortgage Bonds, due November 1, 2011
BGE	$60 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012
Exelon Corporate	$400 million of 4.45% 2005 Senior Notes, due June 15, 2010
Generation	$1 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
Generation	$13 million of Montgomery County Series 1994 B Tax Exempt Bonds with variable interest rates, due June 1, 2029
Generation	$17 million of Indiana County Series 2003 A Tax Exempt Bonds with variable interest rates, due June 1, 2027
Generation	$19 million of York County Series 1993 A Tax Exempt Bonds with variable interest rates, due August 1, 2016
Generation	$23 million of Salem County Series 1993 A Tax Exempt Bonds with variable interest rates, due March 1, 2025
Generation	$24 million of Delaware County Series 1993 A Tax Exempt Bonds with variable interest rates, due August 1, 2016
Generation	$34 million of Montgomery County Series 1996 A Tax Exempt Bonds with variable interest rates, due March 1, 2034
Generation	$83 million of Montgomery County Series 1994 A Tax Exempt Bonds with variable interest rates, due June 1, 2029
ComEd	$1 million of 4.75% sinking fund debentures, due December 1, 2011
ComEd	$212 million of 4.74% First Mortgage Bonds, due August 15, 2010
PECO	$806 million of 6.52% PETT Transition Bonds, due September 1, 2010
BGE	$57 million of 5.47% fixed rate Rate Stabilization Bonds, due October 1, 2012

From time to time and as market conditions warrant, the Registrants may engage in long-term debt retirements via tender offers, open market repurchases or other viable options to reduce debt on their respective balance sheets.

Dividends. Cash dividend payments and distributions during 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Exelon	$1,733	$1,393	$1,389
Generation	1,626	172	1,508
ComEd	105	300	310
PECO	347	352	228
BGE	13	98[(a)]	13

(a) Dividends on common stock for $85 million were paid to Constellation for the year ended December 31, 2011.

First Quarter 2013 Dividend. On February 6, 2013, the Exelon Board of Directors declared a first quarter 2013 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 8, 2013, to shareholders of record of Exelon at the end of the day on February 19, 2013.

Revised Dividend Policy. On February 6, 2013, the Exelon Board of Directors approved a revised dividend policy which contemplates a regular $0.31 per share quarterly dividend on Exelon's common stock payable beginning in the second quarter of 2013 (or $1.24 per share on an annualized basis), subject to quarterly declarations by the Exelon Board of Directors. The second quarter 2013 quarterly dividend of $0.31 per share on Exelon's common stock is expected to be approved by the Exelon Board of Directors in the second quarter of 2013.

Short-Term Borrowings. Short-term borrowings incurred (repaid) during 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
ComEd	$ —	$—	$(155)
BGE	—	—	(46)
Other [(a)]	(197)	161	—
Exelon	$(197)	$161	$(201)

(a) Other primarily consists of corporate operations and BSC.

Retirement of Long-Term Debt to Financing Affiliates. There were no retirement of long-term debt to financing affiliates during 2012, 2011 and 2010 by the Registrants.

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2012, 2011 and 2010 by Registrant were as follows:

	2012	2011	2010
Generation	$48	$ 30	$ 62
ComEd	11	11	2
PECO [(a)]	9	18	223
BGE	66	—	—

(a) Reflects payment received to reduce the receivable from parent of $180 million for the year ended December 31, 2010 and was completely repaid as of December 31, 2010.

Other. Other significant financing activities for Exelon for 2012, 2011 and 2010 were as follows:

- Exelon received proceeds from employee stock plans of $72 million, $38 million and $48 million during 2012, 2011 and 2010, respectively.

Credit Matters

Market Conditions

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large diversified credit facilities. The credit facilities include $8.3 billion in aggregate total commitments of which $3.8 billion was available as of December 31, 2012, and of which no financial institution has more than 10% of the aggregate commitments for Exelon, Generation, ComEd, PECO and BGE. The Registrants had access to the commercial paper market during 2012 to fund their short-term liquidity needs, when necessary. The Registrants routinely review the sufficiency of their liquidity position, including appropriate sizing of credit facility commitments, by performing various stress test scenarios, such as commodity price movements, increases in margin-related transactions, changes in hedging levels, and the impacts of hypothetical credit downgrades. The Registrants have continued to closely monitor events in the financial markets and the financial institutions associated with the credit facilities, including monitoring credit ratings and outlooks, credit default swap levels, capital raising and merger activity. See PART I. ITEM 1A Risk Factors for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flows from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of December 31, 2012, it would have been required to provide incremental collateral of approximately $1,920 million, which is well within its current available credit facility capacities of approximately $5.6 billion, which includes $1,920 million of collateral obligations for derivatives, non-derivatives, normal purchase normal sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements. If ComEd lost its investment grade credit rating as of December 31, 2012, it would have been required to provide incremental collateral of approximately $218 million, which is well within its current available credit facility capacity of approximately $1.0 billion. If PECO lost its investment grade credit rating as of December 31, 2012, it would not be required to provide collateral pursuant to PJM's credit policy and could have been required to provide collateral of approximately $35 million related to its natural gas procurement contracts, which, in the aggregate, is well within PECO's current available credit facility capacity of approximately $599 million. If BGE lost its investment grade credit rating as of December 31, 2012, it would have been required to provide collateral of $3 million pursuant to PJM's credit policy and could have been required to provide collateral of approximately $124 million related to its natural gas procurement contracts, which, in the aggregate, is well within BGE's current available credit facility capacity of approximately $600 million.

Exelon Credit Facilities

See Note 11 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' credit facilities and short term borrowing activity.

Other Credit Matters

Capital Structure. At December 31, 2012, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO	BGE
Long-term debt	45%	27%	43%	36%	46%
Long-term debt to affiliates (a)	2	10	2	3	5
Common equity	52	—	55	55	45
Member's equity	—	63	—	—	—
Preferred securities	—	—	—	2	4
Commercial paper and notes payable	1	—	—	4	—

(a) Includes approximately $648 million, $206 million, and $184 million owed to unconsolidated affiliates of Exelon, ComEd and PECO, respectively, and $258 million owed to a consolidated affiliate of BGE that all qualify as special purpose entities under the applicable authoritative guidance. These special purpose entities were created for the sole purposes of issuing mandatorily redeemable trust preferred securities of ComEd, PECO and BGE. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding the authoritative guidance for VIEs.

Intercompany Money Pool. To provide an additional short-term borrowing option that will generally be more favorable to the borrowing participants than the cost of external financing, Exelon operates an intercompany money pool. As of January 10, 2006, ComEd voluntarily suspended its participation in the money pool. Generation, PECO and BSC may participate in the intercompany money pool as lenders and borrowers, and Exelon may participate as a lender. As a result of the ring-fencing measures required by the MDPSC, BGE does not participate in the intercompany money pool. Funding of, and borrowings from, the intercompany money pool are predicated on whether the contributions and borrowings result in economic benefits. Interest on borrowings is based on short-term market rates of interest or, if from an external source, specific borrowing rates. Maximum amounts contributed to and borrowed from the intercompany money pool by participant during 2012 are described in the following table in addition to the net contribution or borrowing as of December 31, 2012:

	Maximum Contributed	Maximum Borrowed	December 31, 2012 Contributed (Borrowed)
Generation	$—	$258	$ —
PECO	309	—	—
BSC	—	206	(119)
Exelon Corporate	119	N/A	119

Shelf Registration Statements. The Registrants have combined a shelf registration statement with the SEC. As of December 31, 2012, that shelf registration statement remained effective and provides for the sale of unspecified amounts of securities. The ability of each Registrant to sell securities off that shelf registration statement or to access the private placement markets will depend on a number of factors at the time of the proposed sale, including other required regulatory approvals, as applicable, the current financial condition of the Registrant, its securities ratings and market conditions.

Regulatory Authorizations. The issuance by ComEd, PECO and BGE of long-term debt or equity securities requires the prior authorization of the ICC, PAPUC and MDPSC, respectively. ComEd, PECO and BGE normally obtain the required approvals on a periodic basis to cover their anticipated financing needs for a period of time or in connection with a specific financing. On February 27, 2012, ComEd received $1.3 billion in long-term debt refinancing authority from the ICC. As of December 31, 2012, ComEd had $1.4 billion available in long-term debt refinancing authority from the ICC and $106 million in new money long-term debt financing authority from the ICC. On October 24, 2012, the PAPUC approved PECO's application for long-term financing authority for $2.5 billion, which is effective through December 31, 2015. As of December 31, 2012, PECO had $1.9 billion available in long-term debt financing authority from the PAPUC. As of December 31, 2012, BGE had $1.2 billion available in long-term financing authority from MDPSC.

FERC has financing jurisdiction over ComEd's, PECO's and BGE's short-term financings and all of Generation's financings. As of December 31, 2012, ComEd and PECO had short-term financing authority from FERC that expires on December 31, 2013 of $2.5 billion and $1.5 billion, respectively. As of December 31, 2012, BGE had short-term financing authority from FERC that expires on December 31, 2014 of $0.7 billion. Generation currently has blanket financing authority that it received from FERC in connection with its market-based rate authority. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.

Exelon's ability to pay dividends on its common stock depends on the receipt of dividends paid by its operating subsidiaries. The payments of dividends to Exelon by its subsidiaries in turn depend on their results of operations and cash flows and other items affecting retained earnings. The Federal Power Act declares it to be unlawful for any officer or director of any public utility "to participate in the making or paying of any dividends of such public utility from any funds properly included in capital account." In addition, under Illinois law, ComEd may not pay any dividend on its stock, unless, among other things, its earnings and earned surplus are sufficient to declare and pay a dividend after provision is made for reasonable and proper reserves, or unless ComEd has specific authorization from the ICC. BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid. There are no other limitations on BGE paying common stock dividends unless: (1) BGE elects to defer interest payments on the 6.20% Deferrable Interest Subordinated Debentures due 2043, and any deferred interest remains unpaid; or (2) any dividends (and any redemption payments) due on BGE's preference stock have not been paid. At December 31, 2012, Exelon had retained earnings of $9,893 million, including Generation's undistributed earnings of $3,168 million, ComEd's retained earnings of $721 million consisting of retained earnings appropriated for future dividends of $2,360 million partially offset by $1,639 million of unappropriated retained deficit, PECO's retained earnings of $593 million and BGE's retained earnings $808 million. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Contractual Obligations

The following tables summarizes Exelon's future estimated cash payments as of December 31, 2012 under existing contractual obligations, including payments due by period. See Note 19 of the Combined Notes to Consolidated Financial Statements for information regarding Exelon's commercial and other commitments, representing commitments potentially triggered by future events.

		Payment due within				
	Total	2013	2014-2015	2016-2017	Due 2018 and beyond	All Other
Long-term debt [(a)]	$18,915	$ 976	$ 3,090	$2,495	$12,354	$—
Interest payments on long-term debt [(b)]	12,156	957	1,711	1,493	7,995	—
Liability and interest for uncertain tax positions [(c)]	305	1	—	—	—	304
Capital leases	30	3	6	8	13	—
Operating leases [(d)]	864	88	156	132	488	—
Purchase power obligations [(e)]	3,516	1,246	1,313	483	474	—
Fuel purchase agreements [(f)]	9,955	1,554	2,764	2,208	3,429	—
Electric supply procurement [(f)]	1,721	741	703	277	—	—
AEC purchase commitments [(f)]	12	4	2	2	4	—
Curtailment services commitments [(f)]	153	49	88	16	—	—
Long-term renewable energy and REC commitments [(g)]	1,659	71	148	156	1,284	—
PJM regional transmission expansion commitments [(h)]	914	218	442	254	—	—
Spent nuclear fuel obligation	1,020	—	—	—	1,020	—
Pension minimum funding requirement [(i)]	2,223	255	599	923	446	—
Total contractual obligations	$53,443	$6,163	$11,022	$8,447	$27,507	$304

(a) Includes $648 million due after 2016 to ComEd, PECO and BGE financing trusts.

(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances. Variable rate interest obligations are estimated based on rates as of December 31, 2012. Includes estimated interest payments due to ComEd, PECO and BGE financing trusts.

(c) As of December 31, 2012, Exelon's liability for uncertain tax positions was $305 million. Exelon was unable to reasonably estimate the timing of liability and interest payments and receipts in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. Exelon has other unrecognized tax positions that were not recorded on the Consolidated Balance Sheet in accordance with authoritative guidance. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information regarding unrecognized tax positions.

(d) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations. Includes estimated cash payments for service fees related to PECO's meter reading operating lease.

(e) Purchase power obligations include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2012, including those related to CENG. Expected payments include certain capacity charges that are contingent on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. These obligations do not include ComEd's SFCs as these contracts do not require purchases of fixed or minimum quantities. See Notes 3 and 19 of the Combined Notes to Consolidated Financial Statements.

(f) Represents commitments to purchase nuclear fuel, natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 19 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

(g) On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(h) Under their operating agreements with PJM, ComEd, PECO and BGE are committed to the construction of transmission facilities to maintain system reliability. These amounts represent ComEd's, PECO's and BGE's expected portion of the costs to pay for the completion of the required construction projects. See Note 3 of Combined Notes to Consolidated Financial Statements for additional information.

(i) These amounts represent Exelon's estimated minimum pension contributions to its qualified plans required under ERISA and the Pension Protection Act of 2006, as well as contributions necessary to avoid benefit restrictions and at-risk status. For Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2018 are not included. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

See Note 19 of the Combined Notes to Consolidated Financial Statements for discussion of Exelon's other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- long-term debt, see Note 11 of the Combined Notes to Consolidated Financial Statements.

- liabilities related to uncertain tax positions, see Note 12 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 19 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 13 and 19 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 3 of the Combined Notes to Consolidated Financial Statements.
- variable interest entities, see Note 1 of the Combined Notes to Consolidated Financial Statements.
- nuclear insurance, see Note 19 of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Exelon is exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief executive officer, chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Risk Oversight Committee of the Exelon Board of Directors on the scope of the risk management activities.

Commodity Price Risk

Commodity price risk is associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon has price risk from commodity price movements. Exelon seeks to mitigate its commodity price risk through the sale and purchase of electricity, fossil fuel, and other commodities.

Generation

Normal Operations and Hedging Activities. Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into physical contracts as well as financial derivative contracts, including forwards, futures, swaps, and options, with approved counterparties to hedge anticipated exposures. Generation believes these instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices. Generation expects the settlement of the majority of its economic hedges, including the ComEd financial swap contract, will occur during 2013 through 2015. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 10 of the Combined Notes to Consolidated Financial Statements.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions which have not been hedged. Generation hedges commodity risk on a ratable basis over the three years leading to the spot market. 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. 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 accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-trading portfolio associated with a $5 reduction in the annual average around-the-clock energy price based on December 31, 2012, market conditions and hedged position would be a decrease in pre-tax net income of approximately $40 million, $440 million and $810 million, respectively, for 2013, 2014 and 2015. Power price sensitivities are derived by adjusting power price assumptions while keeping all other price inputs constant. Generation expects to actively manage its portfolio to mitigate market price risk exposure for its unhedged position. Actual results could differ depending on the specific timing of, and markets affected by, price changes, as well as future changes in Generation's portfolio.

Proprietary Trading Activities. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 12,958 GWh, 5,742 GWh, and 3,625 GWh for the years ended December 31, 2012, 2011 and 2010 respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Trading portfolio activity for the year ended December 31, 2012, resulted in pre-tax losses of $14 million due to net mark-to-market gains of $96 million and realized losses of $110 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $1.9 million of exposure since the merger date and was deemed immaterial prior to the merger. Because of the relative size of the proprietary trading portfolio in comparison to Generation's total gross margin from continuing operations for the year ended December 31, 2012 of $7,376 million, Generation has not segregated proprietary trading activity in the following tables.

Fuel Procurement. Generation procures coal and natural gas through long-term and short-term contracts, and spot-market purchases. Nuclear fuel assemblies are obtained primarily through long-term contracts for uranium concentrates, and long-term contracts for conversion services, enrichment services and fuel fabrication services. The supply markets for coal, natural gas, uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 60% of Generation's uranium concentrate requirements from 2013 through 2017 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial positions. See Note 19 of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

ComEd

The financial swap contract between Generation and ComEd was deemed prudent by the Illinois Settlement Legislation, thereby ensuring that ComEd will be entitled to receive full cost recovery in rates. The change in fair value each period is recorded by ComEd with an offset to a regulatory asset or liability. This financial swap contract between Generation and ComEd expires on May 31, 2013.

ComEd's RFP contracts are deemed to be derivatives that qualify for the normal purchases and normal sales exception under derivative accounting guidance. ComEd does not enter into derivatives for speculative or trading purposes. ComEd is permitted full recovery of its RFP contracts from retail customers with no mark-up.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. Delivery under these contracts began in June 2012. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Notes 3 and 10 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3 of the Combined Notes to the Consolidated Financial Statements. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

PECO has also entered into derivative natural gas contracts, which either qualify for the normal purchases and normal sales exception or have no mark-to-market balances because the derivatives are index priced, to hedge its long-term price risk in the natural gas market. PECO's hedging program for natural gas procurement has no direct impact on its financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 of the Combined Notes to Consolidated Financial Statements.

BGE

BGE procures electric supply for default service customers through full requirements contracts pursuant to BGE's MDPSC-approved SOS program. BGE's full requirements contracts that are considered derivatives qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. Under the SOS program, BGE is permitted to recover its electricity procurement costs from retail customers, plus an administrative fee which includes a shareholder return component and an incremental cost component. However, through December 2016, BGE provides all residential electric customers a credit for the residential shareholder return component of the administrative charge.

BGE has also entered into derivative natural gas contracts, which qualify for the normal purchases and normal sales scope exception, to hedge its price risk in the natural gas market. The hedging program for natural gas procurement has no direct impact on BGE's financial position. However, under BGE's market-based rates incentive mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers.

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 10 of the Combined Notes to Consolidated Financial Statements.

Trading and Non-Trading Marketing Activities. The following detailed presentation of Exelon's, Generation's, ComEd's and PECO's trading and non-trading marketing activities is included to address the recommended disclosures by the energy industry's Committee of Chief Risk Officers (CCRO).

The following table provides detail on changes in Exelon's, Generation's, ComEd's and PECO's mark-to-market net asset or liability balance sheet position from January 1, 2011, to December 31, 2012. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings, as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts. For additional information on the cash flow hedge gains and losses included within accumulated OCI and the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of December 31, 2012, and December 31, 2011, refer to Note 10 of the Combined Notes to Consolidated Financial Statements.

	Generation	ComEd	PECO	Intercompany Eliminations [h]	Exelon
Total mark-to-market energy contract net assets (liabilities) at January 1, 2011 [a]	$ 1,803	$ (971)	$ (9)	$ —	$ 823
Total change in fair value during 2011 of contracts recorded in result of operations	241	—	—	—	241
Reclassification to realized at settlement of contracts recorded in results of operations	(541)	—	—	—	(541)
Ineffective portion recognized in income [b]	9	—	—	—	9
Reclassification to realized at settlement from accumulated OCI [c]	(968)	—	—	456	(512)
Effective portion of changes in fair value—recorded in OCI [d]	827	—	—	(170)	657
Changes in fair value—energy derivatives	—	171[e]	9[f]	(286)	(106)
Changes in collateral	411	—	—	—	411
Changes in net option premium paid/(received)	3	—	—	—	3
Option Premium Amortization [g]	(137)	—	—	—	(137)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2011 [a]	$ 1,648	$ (800)	$—	$ —	$ 848
Contracts Acquired at merger date [i]	140				140
Total change in fair value during 2012 of contracts recorded in result of operations	(159)	—	—	7	(152)
Reclassification to realized at settlement of contracts recorded in results of operations	775	—	—	—	775
Ineffective portion recognized in income [b]	(5)	—	—	—	(5)

	Generation	ComEd	PECO	Intercompany Eliminations [h]	Exelon
Reclassification to realized at settlement from accumulated OCI [c]	(1,368)	—	—	621	(747)
Effective portion of changes in fair value—recorded in OCI [d]	719	—	—	(146)	573
Changes in fair value—energy derivatives	—	507[e]	—	(482)	25
Changes in collateral	(89)	—	—	—	(89)
Changes in net option premium paid/(received)	114	—	—	—	114
Option Premium Amortization [g]	(160)	—	—	—	(160)
Intercompany Elimination of Existing Derivative Contracts with Constellation	(103)				(103)
Other changes in fair value	(7)	—	—	—	(7)
Total mark-to-market energy contract net assets (liabilities) at December 31, 2012 [a]	$ 1,505	$ (293)	$—	$ —	$ 1,212

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For Generation, reflects $5 million and $9 million of changes in cash flow hedge ineffectiveness, of which none was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO for the years ended December 31, 2012 and 2011, respectively.
(c) For Generation, includes $621 million and $451 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011, respectively, and $5 million of losses from reclassifications from accumulated OCI to recognize gains in net income related to settlements of the PECO block contracts for the year ended December 31, 2011.
(d) For Generation, includes $146 million and $170 million of gains related to the changes in fair value of the five-year financial swap with ComEd for the years ended December 31, 2012 and 2011, respectively. Effective prior to the merger, the five-year financial swap between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.
(e) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2012 and 2011, ComEd recorded a regulatory liability of $293 million and $800 million, respectively, related to its mark-to-market derivative liabilities with Generation and unaffiliated suppliers. During 2012 and 2011, this includes $98 million of increases and $170 million of decreases in fair value, respectively, and $566 million and $451 million of realized gains, respectively, due to settlements of ComEd's five-year financial swap with Generation. During 2012 and 2011 this includes $34 million and $110 million, respectively, of increases in fair value, and during 2012 realized losses due to settlements of $5 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(f) For PECO, the changes in fair value are recorded as a change in regulatory assets or liabilities. During the year ended December 31, 2011, PECO's mark-to-market derivative liability was fully amortized, including $5 million related to PECO's block contracts with Generation, in accordance with the terms of the contracts.
(g) Includes $160 million and $137 million of amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of the underlying transactions for the years ended December 31, 2012 and 2011, respectively.
(h) Amounts related to the five-year financial swap between Generation and ComEd and the block contracts between Generation and PECO are eliminated in consolidation.
(i) For Generation, includes $660 million of collateral paid to counterparties, offset by $520 million of unrealized losses on commodity derivative positions.

Fair Values

The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities) net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within						
	2013	2014	2015	2016	2017	2018 and Beyond	Total Fair Value
Normal Operations, Commodity derivative contracts [a][b]:							
Actively quoted prices (Level 1)	$ 80	$ (63)	$ (32)	$10	$ 2	$—	$ (3)
Prices provided by external sources (Level 2)	325	374	134	16	—	(1)	848
methods (Level 3) [c]	168	89	50	30	25	5	367
Total	$573	$400	$152	$56	$ 27	$ 4	$1,212

(a) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts that do not qualify as cash flow hedges are recorded in results of operations.

(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $31 million at December 31, 2012.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2013	**2014**	**2015**	**2016**	**2017**	**2018 and Beyond**	**Total Fair Value**
Normal Operations, Commodity derivative contracts [(a)(b)] *:*							
Actively quoted prices (Level 1)	$ 80	$ (63)	$ (32)	$10	$ 2	$—	$ (3)
Prices provided by external sources (Level 2)	325	374	134	16	—	(1)	848
Prices based on model or other valuation methods (Level 3)	412	106	66	44	38	(6)	660
Total	$817	$417	$168	$70	$ 40	$ (7)	$1,505

(a) Mark-to-market gains and losses on other non-trading hedge and trading derivative contracts are recorded in results of operations. Amounts include a $226 million gain associated with the five-year financial swap with ComEd.
(b) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of $31 million at December 31, 2012.

ComEd

	Maturities Within						
	2013	**2014**	**2015**	**2016**	**2017**	**2018 and Beyond**	**Fair Value**
Prices based on model or other valuation methods [(a)]	$(244)	$(17)	$(16)	$(14)	$(13)	$11	$(293)

(a) Represents ComEd's net assets (liabilities) associated with the five-year financial swap with Generation and the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Credit Risk, Collateral, and Contingent Related Features

Exelon would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. See Note 10 of the Combined Notes to Consolidated Financial Statements for a detail discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2012. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties and an indication of the duration of a company's credit risk by credit rating of the counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through exchanges (i.e. NYMEX, ICE, etc), which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $54 million, $56 million and $31 million, respectively. See Note 22 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2012	**Total Exposure Before Credit Collateral**	**Credit Collateral** [(a)]	**Net Exposure**	**Number of Counterparties Greater than 10% of Net Exposure**	**Net Exposure of Counterparties Greater than 10% of Net Exposure**
Investment grade	$1,984	$347	$1,637	1	$262
Non-investment grade	28	24	4	—	—
No external ratings					
Internally rated—investment grade	512	10	502	1	271
Internally rated—non-investment grade	41	3	38	—	—
Total	$2,565	$384	$2,181	2	$533

Rating as of December 31, 2012	Maturity of Credit Risk Exposure Less than 2 Years	 2-5 Years	 Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$1,553	$319	$112	$1,984
Non-investment grade	15	13	—	28
No external ratings				
Internally rated—investment grade	312	193	7	512
Internally rated—non-investment grade	41	—	—	41
Total	$1,921	$525	$119	$2,565

Net Credit Exposure by Type of Counterparty	As of December 31, 2012
Investor-owned utilities, marketers and power producers	$ 865
Energy cooperatives and municipalities	786
Financial Institutions	422
Other	108
Total	$2,181

(a) As of December 31, 2012, credit collateral held from counterparties where Generation had credit exposure included $344 million of cash and $40 million of letters of credit.

ComEd

Credit risk for ComEd is managed by credit and collection policies, which are consistent with state regulatory requirements. ComEd is currently obligated to provide service to all electric customers within its franchised territory. ComEd records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. The Illinois Settlement Legislation prohibits utilities, including ComEd, from terminating electric service to a residential electric space heat customer due to nonpayment between December 1 of any year through March 1 of the following year. ComEd's ability to disconnect non space-heating residential customers is also impacted by certain weather restrictions, at any time of year, under the Illinois Public Utilities Act. ComEd will monitor the impact of its disconnection practices and will make any necessary adjustments to the provision for uncollectible accounts. ComEd did not have any customers representing over 10% of its revenues as of December 31, 2012. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's recently approved tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. As of December 31, 2012, ComEd's credit exposure to energy suppliers was immaterial.

PECO

Credit risk for PECO is managed by credit and collection policies, which are consistent with state regulatory requirements. PECO is currently obligated to provide service to all retail electric customers within its franchised territory. PECO records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. See Note 1 of the Combined Notes to Consolidated Financial Statements for the allowance for uncollectible accounts policy. In accordance with PAPUC regulations, after November 30 and before April 1, an electric distribution utility or natural gas distribution utility shall not terminate service to customers with household incomes at or below 250% of the Federal poverty level. PECO's provision for uncollectible accounts will continue to be affected by changes in prices as well as changes in PAPUC regulations. PECO did not have any customers representing over 10% of its revenues as of December 31, 2012.

PECO's supplier master agreements that govern the terms of its DSP Program contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2012, PECO had no net credit exposure with suppliers.

PECO does not obtain cash collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $20 million in parental guarantees related to these agreements. As of December 31, 2012, PECO had credit exposure of $7 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE

Credit risk for BGE is managed by credit and collection policies, which are consistent with state regulatory requirements. BGE is currently obligated to provide service to all electric customers within its franchised territory. BGE records a provision for uncollectible accounts to provide for the potential loss from nonpayment by these customers. BGE will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. See Note 1 of the Combined Notes to Consolidated Financial Statements for uncollectible accounts policy. MDPSC regulations prohibit BGE from terminating service to residential customers due to nonpayment from November 1 through March 31 if the forecasted temperature is 32 degrees or below for the subsequent 72 hour period. BGE is also prohibited by the Maryland Public Utilities Article and MDPSC regulations from terminating service to residential customers due to nonpayment if the forecasted temperature is 95 degrees or above for the subsequent 72 hour period. BGE did not have any customers representing over 10% of its revenues as of December 31, 2012.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2012, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2012, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral

Generation

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 10 of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation sells output through bilateral contracts. The bilateral contracts are subject to credit risk, which relates to the ability of counterparties to meet their contractual payment obligations. Any failure to collect these payments from counterparties could have a material impact on Exelon's and Generation's results of operations, cash flows and financial position. As market prices rise above contracted price levels, Generation is required to post collateral with purchasers; as market prices fall below contracted price levels, counterparties are required to post collateral with Generation. In order to post collateral, Generation depends on access to bank credit facilities which serve as liquidity sources to fund collateral requirements. Generation depends on access to bank credit lines which serve as liquidity sources to fund collateral requirements. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

As of December 31, 2012, Generation had $499 million of cash collateral deposits received from counterparties and Generation had $527 million of cash collateral deposits being held by counterparties, of which $31 million in net cash collateral deposits were offset against mark-to-market assets and liabilities. As of December 31, 2012, $3 million of cash collateral received was not offset against net derivative positions because it was not associated with energy-related derivatives. As of December 31, 2011, Generation was holding $542 million of cash collateral deposits received from counterparties. Net cash collateral deposits received of $540 million were offset mark-to-market assets and liabilities. As of December 31, 2011, $2 million of cash collateral received was not offset against net mark-to-market assets and liabilities. See Note 19 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2012, ComEd held immaterial amounts of cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts and held approximately $19 million in the form of cash and letters of credit for both annual and long-term renewable energy contracts. See Notes 3 and 10 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2012, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

BGE

BGE is not required to post collateral under its electric supply contracts. As of December 31, 2012, BGE was not required to post collateral under its natural gas procurement contracts, nor was it holding collateral under its electric supply and natural gas procurement contracts. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs

Generation, ComEd, PECO and BGE participate in all, or some, of the established, real-time energy markets that are administered by PJM, ISO-NE, ISO-NY, CISO, MISO, SPP, AESO, OIESO and ERCOT. In these areas, power is traded through bilateral agreements between buyers and sellers and on the spot markets that are operated by the RTOs or ISOs, as applicable. In areas where there is no spot market, electricity is purchased and sold solely through bilateral agreements. For sales into the spot markets administered by an RTO or ISO, the RTO or ISO maintains financial assurance policies that are established and enforced by those administrators. The credit policies of the RTOs and ISOs may under certain circumstances require that losses arising from the default of one member on spot market transactions be shared by the remaining participants. Non-performance or non-payment by a major counterparty could result in a material adverse impact on the Registrants' results of operations, cash flows and financial positions.

Exchange Traded Transactions

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk.

Long-Term Leases

Exelon's Consolidated Balance Sheets, as of December 31, 2012, included a $693 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of approximately $1.5 billion, less unearned income of $799 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms which are set at prices above the then expected fair market value of the plants. If the lessees do not exercise the fixed purchase options the lessees return the leasehold interests to Exelon and Exelon has the ability to require the lessees to arrange a service contract with a third party for a period following the lease term. In any event, Exelon is subject to residual value risk to the extent the fair value of the assets are less than the residual value. This risk is mitigated by the fair value of the fixed payments under the service contract. The term of the service contract, however, is less than the expected remaining useful life of the plants and, therefore, Exelon's exposure to residual value risk will not be mitigated by payments under the service contract in this remaining period. Lessee performance under the lease agreements is supported by collateral and credit enhancement measures including letters of credit, surety bonds and credit swaps. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Since 2008, the entity providing the credit enhancement for one of the lessees did not meet the credit rating requirements of the lease. Consequently, Exelon has indefinitely extended a waiver and reduction of the rating requirement, which Exelon may terminate by giving 90 days notice to the lessee. Exelon monitors the continuing credit quality of the credit enhancement party.

Exelon performed annual assessments as of July 31, 2012 and 2011 of the estimated fair value of long-term lease investments and concluded that the estimated fair values at the end of the lease terms exceeded the residual values ($1.5 billion as noted above) established at the lease dates and recorded as investments on Exelon's balance sheet. Through December 31, 2012, no events have occurred or circumstances have changed that would require any formal reassessment subsequent to the July 2012 review.

Interest-Rate Risk

Exelon uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Exelon may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2012, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $452 million of notional amounts of pre-issuance hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $2 million decrease in Exelon pre-tax income for the year ended December 31, 2012.

Equity Price Risk

Exelon and Generation maintain trust funds, as required by the NRC, to fund certain costs of decommissioning Generation's nuclear plants. As of December 31, 2012, Generation's decommissioning trust funds are reflected at fair value on its Consolidated Balance Sheets. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to compensate Generation for inflationary increases in decommissioning costs; however, the equity securities in the trust funds are exposed to price fluctuations in equity markets, and the value of fixed-rate, fixed-income securities are exposed to changes in interest rates. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocation in accordance with Generation's NDT fund investment policy. A hypothetical 10% increase in interest rates and decrease in equity prices would result in a $386 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion of equity price risk as a result of the current capital and credit market conditions.

CERTIFICATIONS

The CEO of Exelon has made the required annual certifications for 2012 to the New York Stock Exchange and the Philadelphia Stock Exchange is in compliance with the listing standards of those exchanges. The CEO and CFO have filed with the SEC all required certifications under section 302 of the Sarbanes—Oxley Act of 2002. These certifications are filed as Exhibits 31-1 and 31-2 to Exelon's 2012 Form 10-K.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Exelon's management conducted an assessment of the effectiveness of Exelon's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, Exelon's management concluded that, as of December 31, 2012, Exelon's internal control over financial reporting was effective.

The effectiveness of the Exelon's internal control over financial reporting as of December 31, 2012, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 21, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under item 15(a)(2) present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedules, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedules, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 21, 2013

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2012	2011	2010
Operating revenues	$23,489	$19,063	$18,644
Operating expenses			
Purchased power and fuel	10,157	7,267	6,435
Operating and maintenance	7,961	5,184	4,600
Depreciation and amortization	1,881	1,347	2,075
Taxes other than income	1,019	785	808
Total operating expenses	21,018	14,583	13,918
Equity in losses of unconsolidated affiliates	(91)	(1)	—
Operating income	2,380	4,479	4,726
Other income and (deductions)			
Interest expense, net	(903)	(701)	(792)
Interest expense to affiliates, net	(25)	(25)	(25)
Other, net	346	203	312
Total other income and (deductions)	(582)	(523)	(505)
Income before income taxes	1,798	3,956	4,221
Income taxes	627	1,457	1,658
Net income	1,171	2,499	2,563
Net Income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	11	4	—
Net income on common stock	1,160	2,495	2,563
Other comprehensive loss			
Pension and non-pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs, net of taxes of $1, $(4) and $(7), respectively	1	(5)	(11)
Actuarial loss reclassified to periodic cost, net of taxes of $110, $93 and $79, respectively	168	136	114
Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively	2	4	3
Pension and non-pension postretirement benefit plan valuation adjustment, net of taxes of $(237), $(171) and $(188), respectively	(371)	(250)	(288)
Change in unrealized gain (loss) on cash flow hedges, net of taxes of $(68), $39 and $(107), respectively	(120)	88	(151)
Change in unrealized gain (loss) on marketable securities, net of taxes of $(1), $0 and $0, respectively	2	—	(1)
Change in unrealized gain (loss) on equity investments, net of taxes of $1, $0 and $0, respectively	1	—	—
Other comprehensive loss	(317)	(27)	(334)
Comprehensive income	$ 854	$ 2,472	$ 2,229
Average shares of common stock outstanding:			
Basic	816	663	661
Diluted	819	665	663
Earnings per average common share:			
Basic	$ 1.42	$ 3.76	$ 3.88
Diluted	$ 1.42	$ 3.75	$ 3.87
Dividends per common share	$ 2.10	$ 2.10	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2012	2011	2010
Cash flows from operating activities			
Net income	$ 1,171	$ 2,499	$ 2,563
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	4,079	2,316	2,943
Loss on sale of three Maryland generating stations	272	—	—
Deferred income taxes and amortization of investment tax credits	615	1,457	981
Net fair value changes related to derivatives	(604)	291	(88)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	(157)	14	(105)
Other non-cash operating activities	1,383	770	609
Changes in assets and liabilities:			
Accounts receivable	243	57	(232)
Inventories	26	(58)	(62)
Accounts payable, accrued expenses and other current liabilities	(632)	(254)	472
Option premiums paid, net	(114)	(3)	(124)
Counterparty collateral received (posted), net	135	(344)	(155)
Income taxes	544	492	(543)
Pension and non-pension postretirement benefit contributions	(462)	(2,360)	(959)
Other assets and liabilities	(368)	(24)	(56)
Net cash flows provided by operating activities	6,131	4,853	5,244
Cash flows from investing activities			
Capital expenditures	(5,789)	(4,042)	(3,326)
Proceeds from nuclear decommissioning trust fund sales	7,265	6,139	3,764
Investment in nuclear decommissioning trust funds	(7,483)	(6,332)	(3,907)
Cash and restricted cash acquired from Constellation	964	—	—
Acquisitions of long lived assets	(21)	(387)	(893)
Proceeds from sale of three Maryland generating stations	371	—	—
Proceeds from sales of investments	28	6	28
Purchases of investments	(13)	(4)	(22)
Change in restricted cash	(34)	(3)	423
Other investing activities	136	20	39
Net cash flows used in investing activities	(4,576)	(4,603)	(3,894)
Cash flows from financing activities			
Payment of accounts receivable agreement	(15)	—	—
Changes in short-term debt	(197)	161	(155)
Issuance of long-term debt	2,027	1,199	1,398
Retirement of long-term debt	(1,145)	(789)	(828)
Retirement of long-term debt of variable interest entity	—	—	(806)
Dividends paid on common stock	(1,716)	(1,393)	(1,389)
Proceeds from employee stock plans	72	38	48
Other financing activities	(111)	(62)	(16)
Net cash flows used in financing activities	(1,085)	(846)	(1,748)
Increase (decrease) in cash and cash equivalents	470	(596)	(398)
Cash and cash equivalents at beginning of period	1,016	1,612	2,010
Cash and cash equivalents at end of period	$ 1,486	$ 1,016	$ 1,612

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,411	$ 1,016
Cash and cash equivalents of variable interest entities	75	—
Restricted cash and investments	86	40
Restricted cash and investments of variable interest entities	47	—
Accounts receivable, net		
Customer ($289 and $346 gross accounts receivables pledged as collateral as of December 31, 2012 and December 31, 2011, respectively)	2,787	1,613
Other	1,147	1,000
Accounts receivable, net, of variable interest entities	292	—
Mark-to-market derivative assets	938	432
Unamortized energy contract assets	886	16
Inventories, net		
Fossil fuel	246	208
Materials and supplies	768	656
Deferred income taxes	131	—
Regulatory assets	759	390
Other	560	342
Total current assets	10,133	5,713
Property, plant and equipment, net	45,186	32,570
Deferred debits and other assets		
Regulatory assets	6,497	4,518
Nuclear decommissioning trust funds	7,248	6,507
Investments	1,184	751
Investments in affiliates	22	15
Investment in CENG	1,849	—
Goodwill	2,625	2,625
Mark-to-market derivative assets	937	650
Unamortized energy contract assets	1,073	424
Pledged assets for Zion Station decommissioning	614	734
Deferred income taxes	58	—
Other	1,128	488
Total deferred debits and other assets	23,235	16,712
Total assets	$78,554	$54,995

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Balance Sheets

(In millions)	December 31, 2012	December 31, 2011
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ —	$ 163
Short-term notes payable—accounts receivable agreement	210	225
Long-term debt due within one year	975	828
Long-term debt due within one year of variable interest entities	72	—
Accounts payable	2,446	1,444
Accounts payable of variable interest entities	202	—
Mark-to-market derivative liabilities	352	112
Unamortized energy contract liabilities	455	—
Accrued expenses	1,800	1,255
Deferred income taxes	58	1
Regulatory liabilities	321	197
Dividends payable	4	349
Other	889	560
Total current liabilities	7,784	5,134
Long-term debt	17,190	11,799
Long-term debt to financing trusts	648	390
Long-term debt of variable interest entities	508	—
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,551	8,253
Asset retirement obligations	5,074	3,884
Pension obligations	3,428	2,194
Non-pension postretirement benefit obligations	2,662	2,263
Spent nuclear fuel obligation	1,020	1,019
Regulatory liabilities	3,981	3,627
Mark-to-market derivative liabilities	281	126
Unamortized energy contract liabilities	528	—
Payable for Zion Station decommissioning	432	563
Other	1,650	1,268
Total deferred credits and other liabilities	30,607	23,197
Total liabilities	56,737	40,520
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 855 and 663 shares outstanding at December 31, 2012 and 2011, respectively)	16,632	9,107
Treasury stock, at cost (35 shares held at December 31, 2012 and 2011, respectively)	(2,327)	(2,327)
Retained earnings	9,893	10,055
Accumulated other comprehensive loss, net	(2,767)	(2,450)
Total shareholders' equity	21,431	14,385
BGE preference stock not subject to mandatory redemption	193	—
Noncontrolling interest	106	3
Total equity	21,730	14,388
Total liabilities and shareholders' equity	$78,554	$54,995

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies

Consolidated Statements of Changes in Shareholders' Equity

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss	Noncontrolling Interest	Preferred and Preference Stock	Total Shareholders' Equity
Balance, December 31, 2009	694,565	$ 8,923	$(2,328)	$ 8,134	$(2,089)	$ —	—	$12,640
Net income	—	—	—	2,563	—	—	—	2,563
Long-term incentive plan activity	1,380	60	1	(1)	—	—	—	60
Employee stock purchase plan issuances	644	23	—	—	—	—	—	23
Common stock dividends	—	—	—	(1,392)	—	—	—	(1,392)
Acquisition of Exelon Wind	—	—	—	—	—	3	—	3
Other comprehensive income, net of income taxes of $(221)	—	—	—	—	(334)	—	—	(334)
Balance, December 31, 2010	696,589	$ 9,006	$(2,327)	$ 9,304	$(2,423)	$ 3	$ —	$13,563
Net income	—	—	—	2,495	—	—	4	2,499
Long-term incentive plan activity	861	76	—	—	—	—	—	76
Employee stock purchase plan issuances	662	25	—	—	—	—	—	25
Common stock dividends	—	—	—	(1,744)	—	—	—	(1,744)
Preferred and preference stock dividends	—	—	—	—	—	—	(4)	(4)
Other comprehensive loss, net of income taxes of $(41)	—	—	—	—	(27)	—	—	(27)
Balance, December 31, 2011	698,112	$ 9,107	$(2,327)	$10,055	$(2,450)	$ 3	—	$14,388
Net income	—	—	—	1,160	—	(3)	14	1,171
Long-term incentive plan activity	2,432	126	—	—	—	—	—	126
Employee stock purchase plan issuances	857	26	—	—	—	—	—	26
Common stock dividends	—	—	—	(1,322)	—	—	—	(1,322)
Common stock issuance Constellation merger	188,124	7,365	—	—	—	—	—	7,365
Noncontrolling interest acquired	—	8	—	—	—	106	—	114
BGE preference stock acquired	—	—	—	—	—	—	193	193
Preferred and preference stock dividends	—	—	—	—	—	—	(14)	(14)
Other comprehensive loss, net of income taxes of $(192)	—	—	—	—	(317)	—	—	(317)
Balance, December 31, 2012	889,525	$16,632	$(2,327)	$ 9,893	$(2,767)	$ 106	193	$21,730

See the Combined Notes to Consolidated Financial Statements

1. Significant Accounting Policies

Description of Business

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses. Prior to March 12, 2012, Exelon's principal, wholly owned subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger (the "Merger Agreement"). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation's regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4—Merger and Acquisitions for further information regarding the merger transaction.

Basis of Presentation

Through its business services subsidiary, BSC, Exelon provides its subsidiaries with a variety of support services at cost, including legal, human resources, financial, information technology and supply management services. The costs of BSC, including support services, are directly charged or allocated to the applicable subsidiaries using a cost-causative allocation method. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of gross revenues, total assets and direct labor costs for the allocation base. The results of Exelon's corporate operations are presented as "Other" within the consolidated financial statements and include intercompany eliminations unless otherwise disclosed.

Exelon owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for ComEd, of which Exelon owns more than 99%, PECO, of which Exelon owns 100% of the common stock but none of PECO's preferred securities and BGE, of which Exelon owns 100% of the common stock but none of BGE's preference stock. Exelon has reflected the third-party interests in ComEd, which totaled less than $1 million at December 31, 2012 and December 31, 2011, as equity, PECO's preferred securities as preferred securities of subsidiary, and BGE's preference stock as BGE preference stock not subject to mandatory redemption in its consolidated financial statements. BGE is subject to some ring-fencing measures established by order of the MDPSC. As part of this arrangement, BGE common stock is held directly by RF Holdco LLC, which is an indirect subsidiary of Exelon. GSS Holdings (BGE Utility), an unrelated party, holds a nominal non-economic interest in RF Holdco LLC with limited voting rights on specified matters.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for a retail power supply VIE for which Generation has no ownership interest but does have a controlling financial interest through contractual arrangements; Exelon SHC, Inc., of which Generation owns 99% and the remaining 1% is indirectly owned by Exelon, which is eliminated in Exelon's consolidated financial statements; and certain Exelon Wind projects, of which Generation holds a majority interest ranging from 94% to 99% for certain periods of time, and the remaining interests are included in noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets. See Note 2 for further discussion of Exelon's and Generation's VIEs and the reversionary interests of the Noncontrolling members for certain of these projects.

ComEd owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for RITELine Illinois, LLC of which ComEd owns 75% and an additional 12.5% is indirectly owned by Exelon. Exelon and ComEd have reflected the third-party interests of 12.5% and 25%, respectively, in RITELine Illinois, LLC, which both totaled less than $1 million at December 31, 2012, as equity.

Exelon consolidates the accounts of entities in which Exelon has a controlling financial interest, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% in which Exelon can exercise control over the operations and policies of the investee, or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Where Exelon does not have a controlling financial interest in an entity it applies proportional consolidation, equity method accounting or cost method accounting. Exelon applies proportionate consolidation when it has an undivided interest in an asset and is proportionately liable for its share of each liability associated with the asset. Exelon proportionately consolidates its undivided ownership interests in jointly owned electric plants and transmission facilities, as well as its undivided ownership interests in upstream natural gas exploration and production activities. Under proportionate consolidation, Exelon separately records its proportionate share of the assets, liabilities, revenues and expenses related to the undivided interest in the asset. Exelon applies equity method accounting when it has significant influence over an investee through an ownership in common stock, which generally approximates a 20% to 50% voting interest. Exelon applies equity method accounting to certain investments and joint ventures, including the 50.01% interest in CENG, and certain financing trusts of ComEd and PECO. Under the equity method, Exelon reports its interest in the entity as an investment and Exelon's percentage share of the earnings from the entity as single line items in its financial statements. Exelon uses the cost method if it holds less than 20% of the common stock of an entity. Under the cost method, Exelon reports its investment at cost and recognizes income only to the extent Exelon receives dividends or distributions.

For the year ended December 31, 2012, BGE recorded a $2 million correcting adjustment to reduce electric distribution revenue related to decoupling of 2011 electric distribution revenue, a $3 million correcting adjustment to increase electric operations and maintenance expense related to capitalization of electric transmission costs, and a $5 million correcting adjustment to interest expense to reflect the impacts of amendments of tax positions previously taken on prior-year consolidated income tax returns. BGE has concluded these correcting adjustments are not material to its results of operations or cash flows for the year ended December 31, 2012, or any prior period.

The accompanying consolidated financial statements have been prepared in accordance with GAAP for annual financial statements and in accordance with the instructions to Form 10-K and Regulation S-X promulgated by the SEC.

Each of the Registrant's Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

Use of Estimates

The preparation of financial statements of each of the Registrants in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Areas in which significant estimates have been made include, but are not limited to, the accounting for nuclear decommissioning costs and other AROs, pension and other postretirement benefits, the application of purchase accounting, inventory reserves, allowance for uncollectible accounts, goodwill and asset impairments, derivative instruments, unamortized energy contracts, fixed asset depreciation, environmental costs and other loss contingencies, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications

Certain prior year amounts in Exelon's Consolidated Statements of Cash Flows, Consolidated Statements of Operations and Comprehensive Income and Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not affect net income or cash flows from operating activities.

Accounting for the Effects of Regulation

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulations, which requires ComEd, PECO and BGE to record in their consolidated financial statements the effects of cost-based rate regulation for entities with regulated operations that meet the following criteria: 1) rates are established or approved by a third-party regulator; (2) rates are designed to recover the entities' cost of providing services or products; and (3) there is a reasonable expectation that rates are set at levels that will recover the entities' costs from customers. Exelon, ComEd, PECO and BGE account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC, the PAPUC, and the MDPSC, in the cases of ComEd, PECO and BGE, respectively, under state public utility laws and the FERC under various Federal laws. Regulatory assets and liabilities are amortized and the related expense is recognized in the Consolidated Statements of Operations consistent with the recovery or refund included in customer rates. Exelon believes that it is probable that its currently recorded regulatory assets and liabilities will be recovered and settled, respectively, in future rates. However, Exelon, ComEd, PECO and BGE continue to evaluate their respective abilities to apply the authoritative guidance for accounting for certain types of regulation, including consideration of current events in their respective regulatory and political environments. If a separable portion of ComEd's, PECO's or BGE's business was no longer able to meet the criteria discussed above, the affected entities would be required to eliminate from their consolidated financial statements the effects of regulation for that portion, which could have a material impact on their results of operations and financial positions. See Note 3—Regulatory Matters for additional information.

Revenues

Operating Revenues. Operating revenues are recorded as service is rendered or energy is delivered to customers. At the end of each month, the Registrants accrue an estimate for the unbilled amount of energy delivered or services provided to customers. ComEd records its best estimates of the distribution and transmission revenue impacts resulting from changes in rates that ComEd believes are probable of approval by the ICC and FERC in accordance with its formula rate mechanisms. BGE records its best estimate of the transmission revenue impact resulting from changes in rates that BGE believes are probable of approval by FERC in accordance with its formula rate mechanism. See Notes 3—Regulatory Matters and 5—Accounts Receivable for further information.

RTOs and ISOs. In RTO and ISO markets that facilitate the dispatch of energy and energy-related products, the Registrants generally report sales and purchases conducted on a net hourly basis in either revenues or purchased power on their Consolidated Statements of Operations, the classification of which depends on the net hourly activity. In addition, capacity revenue and expense classification is based on the net sale or purchase position of the Company in the different RTOs and ISOs.

Option Contracts, Swaps and Commodity Derivatives. Certain option contracts and swap arrangements that meet the definition of derivative instruments are recorded at fair value with subsequent changes in fair value recognized as revenue or expense. The classification of revenue or expense is based on the intent of the transaction. For example, gas transactions may be used to hedge the sale of power. This will result in the change in fair value recorded through revenue. As of the merger date, Exelon and Generation have currently elected to de-designate all of their commodity cash flow hedge positions. Premiums received and paid on option contracts are recognized as revenue or expense over the terms of the contracts. Since ComEd is entitled to full recovery of the costs of the financial swap contract with Generation in rates as settlements occur, ComEd records the fair value of the swap as well as an offsetting regulatory asset or liability on its Consolidated Balance Sheets. See Note 3—Regulatory Matters for further information.

Proprietary Trading Activities. Exelon and Generation account for Generation's trading activities under the provisions of the authoritative guidance for accounting for contracts involved in energy trading and risk management activities, which require energy revenues and costs related to energy trading contracts to be presented on a net basis in the income statement. Commodity derivatives used for trading purposes are accounted for using the mark-to-market method with unrealized gains and losses recognized in operating revenues. Refer to Note 10—Derivative Financial Instruments for further discussion.

Income Taxes

Deferred Federal and state income taxes are provided on all significant temporary differences between the book basis and the tax basis of assets and liabilities and for tax benefits carried forward. Investment tax credits have been deferred on Exelon's Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, Exelon accounts for uncertain income tax positions using a benefit recognition model with a two-step approach; a more-likely-than-not recognition criterion and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. Exelon recognizes accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on its Consolidated Statements of Operations.

Pursuant to the IRC and relevant state taxing authorities, Exelon and its subsidiaries file consolidated or combined income tax returns for Federal and certain state jurisdictions where allowed or required. See Note 12—Income Taxes for further information.

Taxes Directly Imposed on Revenue-Producing Transactions

Exelon presents any tax assessed by a governmental authority that is the liability of the Registrants and is directly imposed on a revenue-producing transaction between a seller and a customer on a gross (included in revenues and costs) basis. See Note 20—Supplemental Financial Information for Generation's, ComEd's, PECO's and BGE's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents

Exelon considers investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments

Restricted cash and investments represent funds that are restricted to satisfy designated current liabilities. As of December 31, 2012 and 2011, Exelon Corporate's restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long-term disability benefits. Additionally, Exelon Corporate has funds restricted for merger commitments. In addition, Exelon Corporate's investments include its direct financing lease investments. As of December 31, 2012, Generation's restricted cash and investments primarily included cash at one of its consolidated variable interest entities and, as of 2011, primarily represented funds in escrow related to the acquisition of Shooting Star Wind Project, LLC and cash for payment of certain environmental liabilities. As of December 31, 2012 and 2011, ComEd's restricted cash primarily represented cash collateral held from suppliers associated with ComEd's energy and REC procurement contracts. As of December 31, 2011, PECO's restricted cash primarily represented funds from the sales of assets that were subject to PECO's mortgage indenture. As of December 31, 2012 and 2011, BGE's restricted cash primarily represented funds restricted at its consolidated variable interest entity for repayment of rate stabilization bonds.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2012 and 2011, Exelon's and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2012, Exelon, ComEd, PECO and BGE had short-term investments in Rabbi trusts classified as noncurrent assets.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts reflects Exelon's best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying loss rates developed specifically for each company to the outstanding receivable balance by risk segment. Risk segments represent a group of customers with similar credit quality indicators that are computed based on various attributes, including delinquency of their balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average charge-offs as a percentage of accounts receivable in each risk segment. BGE estimates the allowance for uncollectible accounts on customer receivables by assigning reserve factors for each aging bucket. These percentages were derived from a study of billing progression which determined the reserve factors by aging bucket. ComEd, PECO and BGE customers' accounts are generally considered delinquent if the amount billed is not received by the time the next bill is issued, which normally occurs on a monthly basis. ComEd, PECO and BGE customer accounts are written off consistent with approved regulatory requirements. ComEd's, PECO's and BGE's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC, PAPUC and MDPSC regulations, respectively. See Note 3—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Variable Interest Entities

Exelon accounts for its investments in and arrangements with VIEs based on the authoritative guidance which includes the following specific requirements:

- requires an entity to qualitatively assess whether it should consolidate a VIE based on whether the entity (1) has the power to direct matters that most significantly impact the activities of the VIE, and (2) has the obligation to absorb losses or the right to receive benefits of the VIE that could potentially be significant to the VIE,
- requires an ongoing reconsideration of this assessment instead of only upon certain triggering events,
- amends the events that trigger a reassessment of whether an entity is a VIE, and
- requires the entity that consolidates a VIE (the primary beneficiary) to present separately on the face of its balance sheet (1) the assets of the consolidated VIE, if they can be used to only settle specific obligations of the consolidated VIE, and (2) the liabilities of a consolidated VIE for which creditors do not have recourse to the general credit of the primary beneficiary.

Based on the above accounting guidance, Exelon has adopted the following policies related to variable interest entities:

- Exelon has presented separately on its Consolidated Balance Sheets, to the extent material, the assets of its consolidated VIEs that can only be used to settle specific obligations of the consolidated VIE, and the liabilities of Exelon's consolidated VIEs for which creditors do not have recourse to Exelon's general credit.

- Exelon has qualitatively assessed whether the equity holders of the entity have the power to direct matters that most significantly impact the entity. Exelon has evaluated all existing entities under the new VIE accounting requirements, both those previously considered VIEs and those considered potential VIEs. Exelon's accounting for and disclosure about VIEs did not change materially as a result of these assessments.

See Note 2—Variable Interest Entities for additional information.

Inventories

Inventory is recorded at the lower of weighted average cost or market. Provisions are recorded for excess and obsolete inventory.

Fossil Fuel. Fossil fuel inventory includes the weighted average costs of stored natural gas, propane and oil. The costs of natural gas, propane, coal and oil are generally included in inventory when purchased and charged to fuel expense when used or sold.

Materials and Supplies. Materials and supplies inventory generally includes the weighted average costs of transmission, distribution and generating plant materials. Materials are generally charged to inventory when purchased and expensed or capitalized to property, plant and equipment, as appropriate, when installed or used.

Emission Allowances. Emission allowances are included in inventory (for emission allowances exercisable in the current year) and other deferred debits (for emission allowances that are exercisable beyond one year) and are carried at the lower of weighted average cost or market and charged to fuel expense as they are used in operations.

Marketable Securities

All marketable securities are reported at fair value. Marketable securities held in the NDT funds and BGE's Rabbi trust investments are classified as trading securities and all other securities are classified as available-for-sale securities. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former ComEd and former PECO nuclear generating units (Regulatory Agreement Units) are included in regulatory liabilities at Exelon, ComEd and PECO and in noncurrent payables to affiliates at Generation and in noncurrent receivables from affiliates at ComEd and PECO. Realized and unrealized gains and losses, net of tax, on Generation's NDT funds associated with the former AmerGen nuclear generating units, the Zion generating station and portions of the Peach Bottom nuclear generating units not subject to a regulatory agreement (Non-Regulatory Agreement Units) are included in earnings at Exelon and Generation. Realized and unrealized gains and losses, net of tax, on BGE's Rabbi trust investments are included in earnings at Exelon and BGE. Unrealized gains and losses, net of tax, for ComEd's and PECO's available-for-sale securities are reported in OCI. Any decline in the fair value of ComEd's and PECO's available-for-sale securities below the cost basis is reviewed to determine if such decline is other-than-temporary. If the decline is determined to be other-than-temporary, the cost basis of the available-for-sale securities is written down to fair value as a new cost basis and the amount of the write-down is included in earnings. See Note 13— Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 20—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost. Original cost includes labor, materials and construction overhead. When appropriate, original cost also includes capitalized interest for Generation and Exelon Corporate and AFUDC for regulated property at ComEd, PECO and BGE. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred. For constructed assets, Exelon capitalizes construction-related direct labor and material costs. ComEd, PECO and BGE also capitalized indirect construction costs including labor and related costs of departments associated with supporting construction activities.

Third parties reimburse ComEd, PECO and BGE for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are recorded as a reduction to Property, Plant and Equipment. DOE SGIG funds reimbursed to PECO and BGE are accounted for as CIAC.

For Generation, upon retirement, the cost of property is charged to accumulated depreciation in accordance with the composite method of depreciation. Upon replacement of an asset, the costs to remove the asset, net of salvage, are capitalized to gross plant when incurred as part of the cost of the newly-installed asset and recorded to depreciation expense over the life of the new asset. Removal costs, net of salvage, incurred for property that will not be replaced is charged to operating and maintenance expense as incurred.

For ComEd, PECO and BGE, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's and BGE's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with each utility's regulatory recovery method. ComEd's and BGE's actual incurred removal costs are applied against a related regulatory liability. PECO's removal costs are capitalized to accumulated depreciation when incurred, and recorded to depreciation expense over the life of the new asset constructed consistent with PECO's regulatory recovery method.

Generation's oil and gas exploration and production activities consist of working interests in gas producing fields. Generation accounts for these activities under the successful efforts method of accounting. Acquisition, development and exploration costs are capitalized. Costs of drilling exploratory wells are initially capitalized and later charged to expense if reserves are not discovered or deemed not to be commercially viable. Other exploratory costs are charged to expense when incurred.

See Note 6—Property, Plant and Equipment, Note 7—Jointly Owned Electric Utility Plant and Note 20—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel

The cost of nuclear fuel is capitalized within property, plant and equipment and charged to fuel expense using the unit-of-production method. The estimated disposal cost of SNF is established per the Standard Waste Contract with the DOE and is expensed through fuel expense at one mill ($0.001) per kWh of net nuclear generation. On-site SNF storage costs are capitalized or expensed to operating and maintenance expense as incurred based upon the nature of the costs. A portion of the storage costs are being reimbursed by the DOE since a DOE (or government-owned) long-term storage facility has not been completed.

Nuclear Outage Costs

Costs associated with nuclear outages, including planned major maintenance activities, are expensed to operating and maintenance expense or capitalized to property, plant and equipment (based on the nature of the activities) in the period incurred.

New Site Development Costs

New site development costs represent the costs incurred in the assessment, design and construction of new power generating facilities. Such costs are capitalized when management considers project completion to be probable, primarily based on management's determination that the project is economically and operationally feasible, management and/or the Exelon Board of Directors has approved the project and has committed to a plan to develop it, and Exelon and Generation have received the required regulatory approvals or management believes the receipt of required regulatory approvals is probable. Upon commencement of construction, these costs will be charged to construction work in progress. Capitalized development costs are charged to operating and maintenance expense when project completion is no longer probable. At December 31, 2012 and 2011, Exelon's and Generation's capitalized development costs totaled approximately $1.2 billion and $376 million, respectively, which are included in Property, Plant and Equipment on Exelon's and Generation's Consolidated Balance Sheets. Costs included in the balance as of December 31, 2012 primarily relate to the development of the Antelope Valley project along with other, smaller renewable energy projects. See Note 4—Merger and Acquisitions for additional information on Antelope Valley. Costs included in the balance as of December 31, 2011 primarily relate to land rights and other third-party costs directly associated with the development of certain Exelon Wind projects. Approximately $4 million, $2 million and $6 million of costs were expensed by Exelon and Generation for the years ended December 31, 2012, 2011 and 2010, respectively. These costs primarily related to the possible development of new renewable energy projects.

Capitalized Software Costs

Costs incurred during the application development stage of software projects that are internally developed or purchased for operational use are capitalized. Such capitalized amounts are amortized ratably over the expected lives of the projects when they become operational, generally not to exceed five years. Certain other capitalized software costs are being amortized over longer lives based on the expected life or pursuant to prescribed regulatory requirements. The following table presents net unamortized capitalized software costs and amortization of capitalized software costs by year:

Net unamortized software costs	
December 31, 2012	$499
December 31, 2011	280

Amortization of capitalized software costs[(a)]	
2012	$208
2011	122
2010	104

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012.

Depreciation, Depletion and Amortization

Except for the amortization of nuclear fuel, depreciation is generally recorded over the estimated service lives of property, plant and equipment on a straight-line basis using the composite method. ComEd's and BGE's depreciation includes a provision for estimated removal costs as authorized by the respective regulators. The estimated service lives for ComEd, PECO and BGE are primarily based on the average service lives from the most recent depreciation study for each respective company. The estimated service lives of the nuclear-fuel generating facilities are based on the remaining useful lives of the stations, which assume a 20-year license renewal extension of the operating licenses (to the extent that such renewal has not yet been granted) for all of Generation's operating nuclear generating stations except for Oyster Creek. The estimated service lives of the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the operating licenses. The estimated service lives of the fossil fuel and other renewable generating facilities are based on the remaining useful lives of the stations, which Generation periodically evaluates based on feasibility assessments taking into account economic and capital requirement considerations. See Note 6—Property, Plant and Equipment for further information regarding depreciation.

Depletion of oil and gas exploration and production activities is recorded using the units-of-production method over the remaining life of the estimated proved reserves at the field level for acquisition costs and over the remaining life of proved developed reserves at the field level for development costs. The estimates for gas reserves are based on internal calculations.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement and is included in depreciation and amortization expense on ComEd's, PECO's and BGE's Consolidated Statements of Operations and Comprehensive Income. See Note 3—Regulatory Matters and 20—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's, PECO's and BGE's regulatory assets.

Asset Retirement Obligations

The authoritative guidance for accounting for AROs requires the recognition of a liability for a legal obligation to perform an asset retirement activity even though the timing and/or method of settlement may be conditional on a future event. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. The liabilities associated with Exelon's non-nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years. Changes to the recorded value of an ARO result from the passage of new laws and regulations, revisions to either the timing or amount of estimates of undiscounted cash flows, and estimates of cost escalation factors. AROs are accreted each year to reflect the time value of money for these present value obligations through a charge to operating and maintenance expense in the Consolidated Statements of Operations or, in the case of the majority of ComEd's and PECO's accretion, through an increase to regulatory assets. See Note 13—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC

During construction, Exelon and Generation capitalize the costs of debt funds used to finance non-regulated construction projects. Capitalization of debt funds is recorded as a charge to construction work in progress and as a non-cash credit to interest expense.

Exelon, ComEd, PECO and BGE apply the authoritative guidance for accounting for certain types of regulation to calculate AFUDC, which is the cost, during the period of construction, of debt and equity funds used to finance construction projects for regulated operations. AFUDC is recorded to construction work in progress and as a non-cash credit to AFUDC that is included in interest expense for debt-related funds and other income and deductions for equity-related funds. The rates used for capitalizing AFUDC are computed under a method prescribed by regulatory authorities.

The following table summarizes total incurred interest, capitalized interest and credits to AFUDC by year:

	2012 (a)	2011	2010
Total incurred interest (b)	$1,003	$783	$861
Capitalized interest	67	49	38
Credits to AFUDC debt and equity	25	25	16

(a) Exelon activity for the year ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012.
(b) Includes interest expense to affiliates.

Guarantees

Exelon recognizes, at the inception of a guarantee, a liability for the fair market value of the obligations they have undertaken in issuing the guarantee, including the ongoing obligation to perform over the term of the guarantee in the event that the specified triggering events or conditions occur.

The liability that is initially recognized at the inception of the guarantee is reduced as Exelon is released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of Exelon may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 19—Commitments and Contingencies for additional information.

Asset Impairments

Long-Lived Assets. Exelon evaluates the carrying value of their long-lived assets or asset groups, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. Exelon determines if long-lived assets and asset groups are impaired by comparing their undiscounted expected future cash flows to their carrying value. Cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Cash flows from Generation plant assets are evaluated at a regional portfolio level along with cash flows generated from Generation's supply and risk management activities, including cash flows from contracts that are recorded as intangible contract assets and liabilities on the balance sheet. For ComEd, PECO, and BGE, the lowest level of independent cash flows is determined by evaluation of several factors including the ratemaking jurisdiction in which they operate and the type of service or commodity provided. For ComEd, the lowest level of independent cash flows is transmission and distribution and, for PECO and BGE, the lowest level of independent cash flows is transmission, distribution and gas.

An impairment loss is recorded if the undiscounted expected future cash flows are less than the carrying amount of the long-lived asset or asset group. The amount of the impairment loss recorded is the difference between the estimated fair value of the long-lived asset or asset group and the carrying value.

Conditions that could have an adverse impact on the expected future cash flows and the fair value of the long-lived assets and asset groups include, among other factors, a deteriorating business climate, including current energy and market conditions, revisions to regulatory laws, or plans to dispose of a long-lived asset significantly before the end of its useful life.

Goodwill. Goodwill represents the excess of the purchase price paid over the estimated fair value of the assets acquired and liabilities assumed in the acquisition of a business. Goodwill is not amortized, but is tested for impairment at least annually or on an interim basis if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 8—Intangible Assets for additional information regarding Exelon's and ComEd's goodwill.

Equity Method Investments. Exelon and Generation evaluate equity method investments to determine whether or not they are impaired. An impairment must be recorded when the investment has experienced an other than temporary decline in value. Additionally, if the project in which Generation holds an investment recognizes an impairment loss, Exelon and Generation would record their proportionate share of that impairment loss and evaluate the investment for an other than temporary decline in value. Exelon and Generation continuously monitor issues that potentially could impact future profitability of the equity method investments.

Derivative Financial Instruments

All derivatives are recognized on the balance sheet at their fair value unless they qualify for certain exceptions, including the normal purchases and normal sales exception. Additionally, derivatives that qualify and are designated for hedge accounting are classified as either hedges of the fair value of a recognized asset or liability or of an unrecognized firm commitment (fair value hedge) or hedges of a forecasted transaction or the variability of cash flows to be received or paid related to a recognized asset or liability (cash flow hedge). For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period. For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. Gains and losses from the ineffective portion of any hedge are recognized in earnings immediately. For derivative contracts intended to serve as economic hedges and that do not qualify or are not designated for hedge accounting or the normal purchases and normal sales exception, changes in the fair value of the derivatives are recognized in earnings each period. Amounts classified in earnings are included in revenue, purchased power and fuel or other, net on the Consolidated Statement of Operations based on the activity the transaction is economically hedging. For energy-related derivatives entered into for proprietary trading purposes, which are subject to Exelon's Risk Management Policy, changes in the fair value of the derivatives are recognized in earnings each period. All amounts classified in earnings related to proprietary trading are included in revenue on the Consolidated Statement of Operations. Cash inflows and outflows related to derivative instruments are included as a component of operating, investing or financing cash flows in the Consolidated Statements of Cash Flows, depending on the nature of each transaction.

For derivative commodity contracts, effective with the date of the merger with Constellation, Generation no longer utilizes the election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain probable, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivatives executed to hedge economic risk for commodities are recorded at fair value with changes in fair value recognized through earnings for the combined company.

Revenues and expenses on derivative contracts that qualify, and are designated, as normal purchases and normal sales are recognized when the underlying physical transaction is completed. While these contracts are considered derivative financial instruments, they are not required to be recorded at fair value, but rather are recorded on an accrual basis of accounting. Normal purchases and normal sales are contracts where physical delivery is probable, quantities are expected to be used or sold in the normal course of business over a reasonable period of time and will not be financially settled. As part of Generation's energy marketing business, Generation enters into contracts to buy and sell energy to meet the requirements of its customers. These contracts include short-term and long-term commitments to purchase and sell energy and energy-related products in the energy markets with the intent and ability to deliver or take delivery of the underlying physical commodity. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the applicable requirements, the fair value of the related contract would be recorded on the balance sheet and immediately recognized through earnings at Generation or offset by a regulatory asset or liability at ComEd, PECO and BGE. See Note 10—Derivative Financial Instruments for additional information.

Retirement Benefits

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. Effective March 12, 2012, Exelon became the sponsor of all of Constellation's defined benefit pension and other postretirement benefit plans and defined contribution savings plans.

The measurement of the plan obligations and costs of providing benefits under these plans involve various factors, including numerous assumptions and accounting elections. The assumptions are reviewed annually and at any interim remeasurement of the plan obligations. The impact of assumption changes or experience different from that assumed on pension and other postretirement benefit obligations is recognized over time rather than immediately recognized in the income statement. Gains or losses in excess of the greater of ten percent of the projected benefit obligation or the MRV of plan assets are amortized over the expected average remaining service period of plan participants. See Note 14—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

Equity Investment Earnings (Losses) of Unconsolidated Affiliates

Exelon and Generation include equity in earnings from equity method investments in qualifying facilities, power projects and joint ventures, including Generation's 50.01% interest in CENG, in equity in earnings (losses) of unconsolidated affiliates. Equity in earnings (losses) of unconsolidated affiliates also includes any adjustments to amortize the difference, if any, except for goodwill and land, between their cost in an equity method investment and the underlying equity in net assets of the investee at the date of investment. See Note 22—Related Party Transactions for additional discussion of Exelon's and Generation's investment in CENG.

Exelon and Generation continuously monitor for issues that potentially could impact future profitability of these equity method investments and which could result in the recognition of an impairment loss if such investment experiences an other than temporary decline in value.

New Accounting Pronouncements

Exelon has identified the following new accounting pronouncements that have been recently adopted or issued that may affect Exelon.

Fair Value Measurement

In May 2011, the FASB issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The new guidance does not impact the fair value measurements included in Exelon's Consolidated Financial Statements as of December 31, 2012. The guidance was effective for Exelon beginning with the period ended March 31, 2012 and was required to be applied prospectively. The Company updated the existing fair value disclosures during the first quarter of 2012 to comply with the new requirements for this standard. See Note 9—Fair Value of Financial Assets and Liabilities for new disclosures.

Statement of Comprehensive Income

In June 2011, the FASB issued authoritative guidance requiring entities to present net income and other comprehensive income in a single continuous statement of comprehensive income or in two separate, but consecutive, statements. The new guidance does not change the components that are recognized in net income and the components that are recognized in other comprehensive income. This guidance became effective for Exelon for periods beginning after December 15, 2011 and was required to be applied retroactively. Exelon currently presents a single statement of comprehensive income, consistent with the new guidance.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the impacted income statement line items. Entities only need to disclose the impacted income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance is effective for Exelon for periods beginning after December 15, 2012 and is required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard will not impact Exelon's results of operations, cash flows or financial positions.

Disclosures About Offsetting Assets and Liabilities

In December 2011 (and amended in January 2013), the FASB issued authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. This guidance is effective for Exelon for periods beginning on or after January 1, 2013 and is required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard will not impact Exelon's results of operations, cash flows or financial positions.

2. Variable Interest Entities

Under the applicable authoritative guidance, a VIE is a legal entity that possesses any of the following characteristics: an insufficient amount of equity at risk to finance its activities, equity owners who do not have the power to direct the significant activities of the entity (or have voting rights that are disproportionate to their ownership interest), or equity owners who do not have the obligation to absorb expected losses or the right to receive the expected residual returns of the entity. Companies are required to consolidate a VIE if they are its primary beneficiary, which is the enterprise that has the power to direct the activities that most significantly impact the entity's economic performance.

As of December 31, 2012, Exelon consolidated five VIEs or VIE groups for which the Registrants were the primary beneficiary, and Exelon had significant interests in nine other VIEs for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

Consolidated Variable Interest Entities

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in Exelon's consolidated financial statements at December 31, 2012 and 2011 are as follows:

	December 31,	
	2012 (a)	**2011**
Current assets	$ 550	$ 15
Noncurrent assets	1,802	784
Total assets	$2,352	$799
Current liabilities	$ 685	$181
Noncurrent liabilities	837	77
Total liabilities	$1,522	$258

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.

Except as specifically noted below, the assets in the table above are restricted for settlement of the VIE obligations and the liabilities in the preceding table can only be settled using VIE resources.

***RSB BondCo LLC**.* In 2007, BGE formed RSB BondCo LLC (BondCo), a special purpose bankruptcy remote limited liability company, to acquire and hold rate stabilization property and to issue and service bonds secured by the rate stabilization property. In June 2007, BondCo purchased rate stabilization property from BGE, including the right to assess, collect, and receive non-bypassable rate stabilization charges payable by all residential electric customers of BGE. These charges are being assessed in order to recover previously incurred power purchase costs that BGE deferred pursuant to Senate Bill 1. BGE determined that BondCo is a VIE for which it is the primary beneficiary. As a result, BGE consolidated BondCo.

BondCo's assets are restricted and can only be used to settle the obligations of BondCo. Further, BGE is required to remit all payments it receives from customers for rate stabilization charges to BondCo. During 2012, 2011, and 2010, BGE remitted $85 million, $92 million, and $90 million, respectively, to BondCo.

BGE did not provide any additional financial support to BondCo during 2012 or 2011. Further, BGE does not have any contractual commitments or obligations to provide additional financial support to BondCo unless additional rate stabilization bonds are issued. The BondCo creditors do not have any recourse to the general credit of BGE in the event the rate stabilization charges are not sufficient to cover the bond principal and interest payments of BondCo.

***Retail Gas Group**.* During 2009, Constellation formed two new entities, which now are part of Generation, and combined them with its existing retail gas activities into a retail gas entity group for the purpose of entering into a collateralized gas supply agreement with a third party gas supplier. While Generation owns 100% of these entities, it has been determined that the retail gas entity group is a VIE because there is not sufficient equity to fund the group's activities without the additional credit support that is provided in the form of a parental guarantee. Generation is the primary beneficiary of the retail gas entity group; accordingly, Generation consolidates the retail gas entity group as a VIE.

The third party gas supply arrangement is collateralized as follows:

- The assets of the retail gas entity group must be used to settle obligations under the third party gas supply agreement before it can make any distributions to Generation,
- The third party gas supplier has a collateral interest in all of the assets and equity of the retail gas entity group, and
- As of December 31, 2012, Exelon provided a $75 million parental guarantee to the third party gas supplier in support of the retail gas entity group.

Other than credit support provided by the parental guarantee, Exelon or Generation do not have any contractual or other obligations to provide additional financial support under the collateralized third party gas supply agreement. The third party gas supply creditors do not have any recourse to Exelon's or Generation's general credit other than the parental guarantee.

Retail Power Supply Entity. Generation also consolidates a retail power supply VIE for which Constellation became the primary beneficiary in 2008 as a result of a modification to its contractual arrangements that changed the allocation of the economic risks and rewards of the VIE among the variable interest holders. This entity now sits under Generation Consolidated and the consolidation of this VIE did not have a material impact on Generation's financial results or financial condition.

Solar Project Entity Group. In 2011, Constellation formed a group of solar project limited liability companies to build, own, and operate solar power facilities which are now part of Generation. Additionally, on September 30, 2011, Generation acquired all of the equity interests in Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar PV project in northern Los Angeles County, California, from First Solar Inc. While Generation owns 100% of these entities, it has been determined that certain of the individual solar project entities are VIEs because the entities require additional subordinated financial support in the form of a parental guarantee of debt, loans from the customers in order to obtain the necessary funds for construction of the solar facilities, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the solar project entities that qualify as VIEs because Generation controls the design, construction, and operation of the solar power facilities. Generation provides capital funding to these solar VIE entities for ongoing construction of the solar power facilities. In addition, these solar VIE entities have an aggregate amount of debt with third parties of $220 million for which the creditors have recourse to Generation.

Wind Project Entity Group. Generation owns and operates a number of wind project limited liability entities, the majority of which were acquired on December 9, 2010 when Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind). Generation has evaluated the significant agreements and ownership structures and risks of each of its wind projects and underlying entities, and determined that certain of the entities are VIEs because either the projects have noncontrolling interest holders that absorb variability from the wind projects, or the customers absorb price variability from the entities through the fixed price power and/or REC purchase agreements. Generation is the primary beneficiary of the wind project entities that qualify as VIEs because Generation controls the design, construction, and operation of the wind power facilities. While Generation owns 100% of the majority of the wind project entities, 10 of the projects have noncontrolling equity interests held by third parties, that currently range between 1% and 6%. Of these 10 projects, Generation's current economic interests in nine of the projects are significantly greater than its stated contractual governance rights and all of these projects have reversionary interest provisions that provide the non-controlling interest holder with a purchase option, certain of which are considered bargain purchase prices, which, if exercised, transfers ownership of the projects to the non-controlling interest holder upon either the passage of time or the achievement of targeted financial returns. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its current economic interests in the projects that currently range between 94% and 99%. However, no additional support to these projects beyond what was contractually required has been provided during 2012. As of December 31, 2012, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of the wind VIE entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

Unconsolidated Variable Interest Entities

Exelon's variable interests in unconsolidated VIEs generally include three transaction types: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity method investments, the carrying amount of the investments is reflected on its Consolidated Balance Sheets in investments in affiliates. For the energy purchase and sale contracts and the fuel purchase commitments (commercial agreements), the carrying amount of assets and liabilities in Exelon's Consolidated Balance Sheets that relate to their involvement with the VIEs are predominately related to working capital accounts and generally represent the amounts owed by, or owed to, Exelon for the deliveries associated with the current billing cycles under the commercial agreements. Further, Exelon has not provided or guaranteed the debt or equity support, or provided liquidity arrangements, performance guarantees or other commitments associated with these commercial agreements.

As of December 31, 2012, Exelon did have significant variable interests in and exposure to loss associated with nine VIEs for which it was not the primary beneficiary; including certain equity method investments and certain commercial agreements. As of December 31, 2011, Exelon had a significant variable interest in and exposure to loss associated with one VIE for which they were not the primary beneficiary. The following tables present summary information about the significant unconsolidated VIE entities for which Exelon has exposure to loss:

December 31, 2012	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Total assets [(a)]	$386	$354	$740
Total liabilities [(a)]	219	114	333
Registrants' ownership interest [(a)]	—	97	97
Other ownership interests [(a)]	167	143	310
Registrants' maximum exposure to loss:			
Letters of credit	5	—	5
Carrying amount of equity method investments	—	77	77
Contract intangible asset	8	—	8
Debt and payment guarantees	—	5	5
Net assets pledged for Zion Station decommissioning [(b)]	50	—	50

December 31, 2011	Commercial Agreement VIEs	Equity Method Investment VIEs	Total
Registrants' maximum exposure to loss:			
Net assets pledged for Zion Station decommissioning [(b)]	43	—	43

(a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.

(b) These items represent amounts on Exelon's balance sheet related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $614 million and $734 million as of December 31, 2012 and December 31, 2011, respectively; offset by payables to ZionSolutions LLC of $564 million and $691 million as of December 31, 2012 and December 31, 2011, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE. See Note 13—Asset Retirement Obligations for further discussion.

Exelon assesses the risk of a loss equal to its maximum exposure to be remote and, accordingly has not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no agreements with, or commitments by, third parties that would affect the fair value or risk of its variable interests in these variable interest entities.

Energy Purchase and Sale Agreements. In March 2005, Constellation, to which Generation is now a successor, closed a transaction in which Generation assumed from a counterparty two power sales contracts with previously existing VIEs. The VIEs previously were created by the counterparty to issue debt in order to monetize the value of the original contracts to purchase and sell power. Under the power sales contracts, Generation sells power to the VIEs which, in turn, sell that power to an electric distribution utility through 2013. In connection with this transaction, a third party acquired the equity of the VIEs and Generation loaned that party a portion of the purchase price. If the electric distribution utility were to default under its obligation to buy power from the VIEs, the equity holder could transfer its equity interests to Generation in lieu of repaying the loan. In this event, Generation would have the right to seek recovery of its losses from the electric distribution utility. As a result, Generation has concluded that consolidation is not required.

ZionSolutions. Generation has an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 13— Asset Retirement Obligations. Under this agreement, ZionSolutions can put the assets and liabilities back to Generation when decommissioning is complete. Generation has evaluated this agreement and determined that, through the put option, it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required.

Fuel Purchase Commitments. Generation's customer supply operations include the physical delivery and marketing of power obtained through its generating capacity, and long-, intermediate-and short-term contracts. Generation also has contracts to purchase fuel supplies for nuclear and fossil generation. These contracts and Generation's membership in NEIL are discussed in further detail in Note 19—Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that it either has no variable interest in an entity or, where Generation does have a variable interest in an entity, the variable interest is not significant and it is not the primary beneficiary; therefore, consolidation is not required.

For contracts where Generation has a variable interest, the level of variability being absorbed through the contracts is not considered significant because of the small proportion of the entities' activities encompassed by the contracts with Generation. Further, Generation has considered which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE and thus is considered the primary beneficiary and is required to consolidate the entity. The primary beneficiary must also have exposure to significant losses or the right to receive significant benefits from the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of the facilities. Facilities represent power plants, sources of uranium and fossil fuels, or plants used in the uranium conversion, enrichment and fabrication process. Generation does not have control over the operation and maintenance of the facilities considered VIEs, and it does not bear operational risk of the facilities. Furthermore, Generation has no debt or equity investments in the entities and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 19—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to have significant variable interests in these entities or be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

ComEd, PECO and BGE

ComEd's, PECO's, and BGE's retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. See Note 3—Regulatory Matters and Note 19—Commitments and Contingencies for additional information on these contracts. ComEd, PECO and BGE have evaluated these types of contracts and have historically determined that either there is no significant variable interest in the entity, or where either ComEd, PECO or BGE does have a significant variable interest in a VIE, ComEd, PECO or BGE would not be the primary beneficiary and, therefore, consolidation would not be required.

For contracts where ComEd, PECO or BGE is considered to have a significant variable interest, consideration is given to which interest holder has the power to direct the activities that most significantly affect the economic performance of the VIE. In general, the most significant activity of the VIEs is the operation and maintenance of their production or procurement processes related to electricity, RECs, AECs or natural gas. ComEd, PECO and BGE do not have control over the operation and maintenance of the entities and they do not bear operational risk related to the associated activities. Generally, the carrying amounts of assets and liabilities in ComEd's, PECO's, and BGE's Consolidated Balance Sheets that relate to their involvement with VIEs generally represent the amounts owed by the utilities for the purchases associated with the current billing cycles under the contracts. As of December 31, 2012, the total amount of accounts payable owed by the utilities under agreements with VIEs was not material. In addition, variability from these contracts is mitigated by the fact that the utilities are able to recover costs incurred under purchase agreements through customer rates. Furthermore, ComEd, PECO and BGE do not have any debt or equity investments in any VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 19—Commitments and Contingencies. Accordingly, none of ComEd, PECO or BGE considers itself to be the primary beneficiary of any VIEs as a result of commercial arrangements.

PECO

PETT, a financing trust, was created in 1998 by PECO to purchase and own intangible transition property (ITP) and to issue transition bonds to securitize $5 billion of PECO's stranded cost recovery authorized by the PAPUC pursuant to the Competition Act. PETT was consolidated in Exelon's and PECO's financial statements on January 1, 2010 pursuant to authoritative guidance relating to the consolidation of VIEs that became effective on that date. Under the guidance, PECO concluded that it was the primary beneficiary of PETT due to PECO's involvement in the design of PETT, its role as servicer, and its right to dissolve PETT and receive any of its remaining assets following retirement of the transition bonds and payment of PETT's other expenses. The consolidation of PETT did not have a significant impact on PECO's results of operations or statement of cash flows. Upon retirement of the outstanding transition bonds on September 1, 2010, the remaining cash balance was remitted to PECO, and PETT was dissolved on September 20, 2010.

3. Regulatory Matters

The following matters below discuss the current status of Exelon's material regulatory and legislative proceedings.

Illinois Regulatory Matters

Energy Infrastructure Modernization Act

Background

EIMA provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois' electric utility infrastructure. EIMA allows the recovery of costs by a utility through a pre-established performance-based formula rate tariff, approved by the ICC. ComEd made an initial contribution of $15 million (recognized as expense in 2011) to a new Science and Technology Innovation Trust fund on July 31, 2012, and will make recurring annual contributions of $4 million, the first of which was made on December 31, 2012, which will be used for customer education for as long as the AMI Deployment Plan remains in effect. In addition, ComEd will contribute $10 million per year for five years, as long as ComEd is subject to EIMA, to fund customer assistance programs for low-income customers, which amounts will not be recoverable through rates. These contributions also began in 2012.

Formula Rate Tariff

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The primary purpose of that proceeding was to establish the formula rate under which rates will be calculated going-forward, and the initial rates, which went into effect in late June 2012. On May 29, 2012, the ICC issued an Order (May Order) in that proceeding. The May Order reduced the annual revenue requirement by $168 million, or approximately $110 million more than proposed by ComEd. Of this incremental revenue requirement reduction, approximately $50 million reflected the ICC's determination that certain costs should be recovered through alternative rate recovery tariffs available to ComEd or will be reflected in a subsequent annual reconciliation, thereby primarily delaying the timing of cash flows. The incremental revenue reduction also reflected a $35 million reduction for the disallowance of return on ComEd's pension asset, a $10 million reduction for incentive compensation related adjustments, and $15 million of reductions for various adjustments for cash working capital, operating reserves, and other technical items. In the second quarter of 2012, ComEd recorded a total reduction of revenue of approximately $100 million pre-tax to decrease the regulatory asset for 2011 and for the first three months of 2012 consistent with the terms of the May Order.

On June 22, 2012, the ICC granted an expedited rehearing on some of the issues raised by the May Order, including ComEd's pension asset recovery. On October 3, 2012, the ICC issued its final order (Rehearing Order) in that rehearing, adopting ComEd's position on the return on its pension asset, resulting in an increase in ComEd's annual revenue requirement. In two other areas, the ICC ruled against ComEd by reaffirming use of an average rather than year-end rate base in ComEd's reconciliation revenue requirement; and amending its prior order to provide a short-term debt rate as the appropriate interest rate to apply to under/over recoveries of incurred costs. ComEd filed an appeal of the May Order and the Rehearing Order in court on October 4, 2012. In the fourth quarter of 2012 ComEd recorded an increase in revenue of approximately $135 million pre-tax consistent with the terms of the Rehearing Order, of which $75 million pre-tax reflects the reinstatement of the 2011 return on pension asset and $60 million pre-tax reflects the return on pension asset costs for 2012. New rates reflecting the impacts of the Rehearing Order went into effect in November 2012.

Capital Investment

On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under that plan, ComEd will invest approximately $2.6 billion over ten years to modernize and storm-harden its distribution system and to implement smart grid technology. These investments will be incremental to ComEd's historical level of capital expenditures. The filing with the ICC specifically included ComEd's $233 million investment plan for 2012. On April 23, 2012, ComEd filed its initial AMI Deployment Plan with the ICC. On June 22, 2012, the ICC approved the AMI Deployment Plan with certain modifications. However, as a result of the Rehearing Order above, ComEd is delaying certain elements of the AMI Deployment Plan, including the installation of additional smart meters. ComEd outlined the new deployment schedule within testimony provided in the AMI Plan Rehearing on October 3, 2012. As a result of the Rehearing Order, ComEd has deferred approximately $50 million of the 2012 AMI Deployment Plan and $15 million of 2012 planned capital investment to future years. On December 5, 2012, the ICC approved ComEd's revised AMI deployment plan. Under the AMI deployment schedule, ComEd will be taking meters out of service prior to the end of their original service lives, which resulted in recording accelerated depreciation for the remaining carrying value of the meters. The Order provides for full recovery of the cost of these early retired meters and, therefore, ComEd recorded a regulatory asset of $7 million for the accelerated depreciation of these meters in the fourth quarter of 2012.

Annual Reconciliation

ComEd will file an annual reconciliation of the revenue requirement in effect in a given year to reflect actual costs that the ICC determines are prudently and reasonably incurred for such year. ComEd made its initial 2011 reconciliation filing on April 30, 2012, which reconciled the 2011 revenue requirement in effect to ComEd's actual 2011 costs incurred. The ICC's final order, issued on December 20, 2012, increased the revenue requirement by $73 million, in conformity with the formula rate structure provided in the May and Rehearing Orders. The rates took effect in January 2013. A similar reconciliation with respect to 2012 will be filed in second quarter 2013 with any adjustments to rates taking effect in January 2014. As of December 31, 2012, and December 31, 2011, ComEd recorded a net regulatory asset of $209 million and $84 million, respectively, reflecting ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide for recovery of prudent and reasonable costs incurred, consistent with the ICC's approved distribution formula rate structure per the May and Rehearing Orders.

Appeal of 2007 Illinois Electric Distribution Rate Case. 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. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). The Court issued a decision on September 30, 2010, ruling against ComEd on the treatment of post-test year accumulated depreciation and the recovery of system modernization costs via a rider (Rider SMP).

The Court held the ICC abused its discretion in not reducing ComEd's rate base to account for an additional 18 months of accumulated depreciation while including post-test year pro forma plant additions through that period (the same position ComEd took in its 2010 electric distribution rate case (2010 Rate Case) discussed below). ComEd continued to bill rates as established under the ICC's order in the 2007 Rate Case until June 1, 2011, when the rates set in the 2010 Rate Case became effective. In August 2011, ComEd filed testimony in the remand proceeding that no refunds should be required. The ICC subsequently initiated a proceeding on remand. On February 23, 2012, the ICC issued an order on remand in the proceeding requiring ComEd to provide a refund of approximately $37 million to customers related to the treatment of post-test year accumulated depreciation issue. On March 26, 2012, ComEd filed a notice of appeal with the Court.

ComEd has recognized for accounting purposes its best estimate of any refund obligation, as discussed above.

Advanced Metering Program Proceeding In October 2009, the ICC approved a modified version of ComEd's system modernization rider proposed in the 2007 Rate Case, Rider AMP (Advanced Metering Program). ComEd collected approximately $24 million under Rider AMP through December 31, 2011. Several other parties, including the Illinois Attorney General, appealed the ICC's order on Rider AMP. In ComEd's 2010 electric distribution rate case, the ICC approved ComEd's transfer of other costs from recovery under Rider AMP to recovery through electric distribution rates. On March 19, 2012, the Court reversed the ICC's approval of Rider AMP, concluding that the ICC's October 2009 approval of the rider constituted single-issue ratemaking. ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court on April 23, 2012. The Illinois Supreme Court denied the Petition on September 26, 2012, and returned the matter to the ICC to calculate a refund amount. ComEd believes any refund obligation associated with Rider AMP should be prospective from no earlier than the date of the Court's order on March 19, 2012, and should not have a material impact on ComEd and Exelon.

2010 Illinois Electric Distribution Rate Case. On June 30, 2010, ComEd requested ICC approval for an increase of $396 million to its annual delivery services revenue requirement. This request was subsequently reduced to $343 million to account for changes in tax law, corrections, acceptance of limited adjustments proposed by certain parties and the amounts expected to be recovered in the AMI pilot program tariff discussed above. The request to increase the annual revenue requirement was to allow ComEd to recover the costs of substantial investments made since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and OPEB, since ComEd's rates were last determined. The original requested rate of return on common equity was 11.5%. In addition, ComEd requested future recovery of certain amounts that were previously recorded as expense that would allow ComEd to recognize a one-time benefit of up to $40 million (pre-tax). The requested increase also included $22 million for increased uncollectible accounts expense, which would increase the threshold for determining over/under recoveries under ComEd's uncollectible accounts tariff.

On May 24, 2011, the ICC issued an order in ComEd's 2010 rate case, which became effective on June 1, 2011. The order approved a $143 million increase to ComEd's annual delivery services revenue requirement and a 10.5% rate of return on common equity. As expected, the ICC followed the Court's position on the post-test year accumulated depreciation issue. The order allowed ComEd to establish or reestablish a net amount of approximately $40 million of previously expensed plant balances or new regulatory assets, which is reflected as a reduction in operating and maintenance expense and income tax expense for the year ended December 31, 2012. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervener in the 2010 Rate Case. The order has been appealed to the Court by several parties. ComEd cannot predict the result of these appeals.

Utility Consolidated Billing and Purchase of Receivables. In November 2008, the Illinois Public Utilities Act was amended to require ComEd to file tariffs establishing Utility Consolidated Billing and Purchase of Receivables services. On December 15, 2010, the ICC approved ComEd's tariff offering Purchase of Receivables with Consolidated Billing (PORCB) services for RES. Since the first quarter of 2011, ComEd has been required to buy certain RES receivables, primarily residential and small commercial and industrial customers, at the option of the RES, for electric supply service and then include those amounts on ComEd's bill to customers. Receivables are purchased at a discount to compensate ComEd for uncollectible accounts. ComEd produces consolidated bills for the aforementioned retail customers reflecting charges for electric delivery service and purchased receivables. As of December 31, 2012, the balance of purchased accounts receivable associated with PORCB was $55 million. Under the tariff, ComEd recovers from RES and customers the costs for implementing and operating the program. A number of municipalities, including the City of Chicago, have announced their intention to switch to RES electric supply as a result of referenda voted on in November 2012. The City of Chicago switching will occur in the first quarter of 2013. The other municipalities are expected to switch during the first half of 2013. As a result, ComEd expects a significant increase in the amount of RES receivables it will be required to purchase in 2013.

Recovery of Uncollectible Accounts. On February 2, 2010, the ICC issued an order adopting tariffs for ComEd to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and amounts collected in rates annually. As a result of the ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense in the first quarter of 2010 for the cumulative under-collections in 2008 and 2009. In addition, ComEd recorded a one-time charge of $10 million to operating and maintenance expense in the first quarter of 2010 for a contribution to the Supplemental Low-Income Energy Assistance Fund, which is used to assist low-income residential customers.

Illinois Procurement Proceedings. ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. Since June 2009, under the Illinois Settlement Legislation, 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. On February 17, 2012, the ICC approved the IPA's procurement plan covering the period June 2012 through May 2017. As of December 31, 2012, ComEd had completed the ICC-approved procurement process for its energy requirements through May 2013 as well as a portion of its requirements for each of the procurement periods ending in May 2014 and May 2015.

EIMA discussed above contains a provision for the IPA to conduct procurement events for energy and REC requirements for the June 2013 through December 2017 period. The procurement events mandated under EIMA were completed during February 2012.

The Illinois Settlement Legislation discussed below requires ComEd to purchase an increasing percentage of its electricity requirements from renewable energy resources. On December 17, 2010, ComEd entered into 20-year contracts with several unaffiliated suppliers regarding the procurement of long-term renewable energy and associated RECs. The long-term renewables purchased will count towards satisfying ComEd's obligation under the state's RPS and all associated costs will be recoverable from customers. As of December 31, 2012, ComEd has completed the ICC-approved procurement process for RECs through May 2013. See Note 10—Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation and long-term renewable energy contracts.

On December 19, 2012, the ICC issued an order directing ComEd and Ameren (the Utilities) to enter into sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The proposed term of the agreement is 20 years. The development was approved by the DOE on February 4, 2013. The sourcing agreement is currently being drafted and approved under a separate proceeding, with a final order expected in 2013. The sourcing agreement is expected to stipulate that the Utilities will pay (or receive) the difference between FutureGen's contract prices and the revenues FutureGen receives for capacity and energy from bidding the unit into the MISO markets. The order also directs the Utilities to recover (or pass along) the difference from the Utilities' distribution system customers, regardless of whether they purchase electricity from the Utility or from an alternative electric generation supplier. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December order by expanding the parties to the sourcing agreement to also include RES suppliers. On January 29, 2013, the ICC denied ComEd's rehearing request. Depending on the precise terms of the sourcing agreement, the eventual market conditions, and the manner of cost recovery, the sourcing agreement could have a material adverse impact on Exelon's and ComEd's cash flows and financial positions.

On December 19, 2012, the ICC approved the IPA's 2013 procurement plan. In response to the increased number of ComEd's customers purchasing their energy from alternative energy suppliers on their own or through municipal aggregation, the plan does not propose any new REC procurements for the period June 2013—May 2014. Additionally, the IPA plan provides that curtailment of the existing long-term contracts for renewable energy and RECs be considered. The ICC concluded that the magnitude of this curtailment shall be determined based upon the March 2013 forecast update and that any such reduction shall be applied proportionately to each of the long-term contracts consistent with the terms of the contracts on an equal, pro-rata basis.

Illinois Settlement Legislation. The Illinois Settlement Legislation was signed into law in August 2007 following a settlement resulting from extensive discussions with legislative leaders in Illinois, ComEd, Generation and other utilities and generators in Illinois to address concerns about higher electric bills without rate freeze, generation tax or other legislation that Exelon believes would be harmful to consumers of electricity, electric utilities, generators of electricity and the State of Illinois. Various Illinois electric utilities, their affiliates and generators of electricity agreed to contribute approximately $1 billion over a period of four years that ended in 2010 to programs to provide rate relief to Illinois electricity customers and funding for the IPA. ComEd committed to issue $64 million in rate relief credits to customers or to fund various programs to assist customers. Generation committed to contribute an aggregate of $747 million, consisting of $435 million to pay ComEd for rate relief programs for ComEd customers, approximately $308 million for rate relief programs for customers of other Illinois utilities and approximately $5 million for partially funding operations of the IPA. The contributions were recognized in the financial statements of Generation and ComEd as rate relief credits were applied to customer bills by ComEd and other Illinois utilities or as operating expenses associated with the programs were incurred. As of December 31, 2010, Generation and ComEd had fulfilled their commitments under the Illinois Settlement Legislation.

During 2010, Generation and ComEd recognized net costs from their contributions pursuant to the Illinois Settlement Legislation in their Consolidated Statements of Operations as follows:

Year Ended December 31, 2010	Generation	ComEd	Total Credits Issued to ComEd Customers
Credits to ComEd customers [(a)]	$14	$ 1	$ 15
Credits to other Illinois utilities' customers [(a)]	7	n/a	n/a
Total incurred costs	$21	$ 1	$ 15

(a) Recorded as a reduction in operating revenues.

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

Since June 1, 2008, utilities have been required to procure cost-effective renewable energy resources in amounts that equal or exceed 2% of the total electricity that each electric utility supplies to its eligible retail customers. ComEd is also required to acquire amounts of renewable energy resources that will cumulatively increase this percentage to at least 10% by June 1, 2015, with an ultimate target of at least 25% by June 1, 2025. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2012, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. ComEd currently retires all RECs upon transfer and acceptance. ComEd is permitted to recover procurement costs of RECs from retail customers without mark-up through rates. See Note 19—Commitments and Contingencies for information regarding ComEd's future commitments for the procurement of RECs.

Pennsylvania Regulatory Matters

2010 Pennsylvania Electric and Natural Gas Distribution Rate Cases. On December 16, 2010, the PAPUC approved the settlement of PECO's electric and natural gas distribution rate cases, which were filed in March 2010, providing increases in annual service revenue of $225 million and $20 million, respectively. The electric settlement provides for recovery of PJM transmission service costs on a full and current basis through a rider. The approved electric and natural gas distribution rates became effective on January 1, 2011.

In addition, the settlements included a stipulation regarding how tax benefits related to the application of any new IRS guidance on repairs deduction methodology are to be handled from a rate-making perspective. The settlements require that the expected cash benefit from the application of any new guidance to tax years prior to 2011 be refunded to customers over a seven-year period. On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for electric transmission and distribution property. PECO adopted the safe harbor and elected a method change for the 2010 tax year. The expected total refund to customers for the tax cash benefit from the application of the safe harbor to costs incurred prior to 2010 is $171 million. On October 4, 2011, PECO filed a supplement to its electric distribution tariff to execute the refund to customers of the tax cash benefit related to the IRC Section 481(a) "catch-up" adjustment claimed on the 2010 income tax return, which is subject to adjustment based on the outcome of IRS examinations. Credits have been reflected in customer bills since January 1, 2012.

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The expected total refund to customers for the tax cash benefit from the application of the new method to costs incurred prior to 2011 is $54 million. This amount is subject to adjustment based on the outcome of IRS examinations. Credits will be reflected in customer bills beginning January 1, 2013. PECO currently anticipates that the IRS will issue guidance in 2013 providing a safe harbor method of accounting for gas transmission and distribution property.

The prospective tax benefits claimed as a result of the new methodology will be reflected in tax expense in the year in which they are claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric and natural gas distribution rate cases. See Note 12 for additional information.

The 2010 electric and natural gas distribution rate case settlements did not specify the rate of return upon which the settlement rates are based, but rather provided for an increase in annual revenue. PECO has not filed a transmission rate case since rates have been unbundled.

Pennsylvania Procurement Proceedings. PECO's current PAPUC approved DSP Program, under which PECO is providing default electric service, has a 29-month term that began on January 1, 2011 and ends May 31, 2013. On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. Under the DSP Programs, PECO is permitted to recover its electric procurement costs from retail default service customers without mark-up through the GSA. The GSA provides for the recovery of energy, capacity, ancillary costs and administrative costs and is subject to adjustments at least quarterly for any over or under collections. In addition, PECO's second DSP Program provides for the recovery of AEPS compliance costs through the GSA rather than a separate AEPS rider. The filing and implementation costs of the current and second DSP Programs were recorded as regulatory assets and are being recovered through the GSA over the DSP Programs 29-month and 24-month terms, respectively.

During 2012, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its last three competitive procurements under the DSP Program for electric supply for default electric service. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

In the second DSP Program, PECO will procure electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes will be served through competitively procured fixed price, full requirements contracts of two years or less. Similar to the current DSP Program, for the large commercial and industrial class load, PECO will competitively procure contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. 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.

In addition, the second DSP Program 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.

Smart Meter and Smart Grid Investments. Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO's SMPIP included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. 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, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 before considering the DOE reimbursements discussed below. As of December 31, 2012, PECO has spent $241 million and $100 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO's existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of December 31, 2012, PECO has received $144 million of the $200 million in reimbursements. PECO's outstanding receivable from the DOE for reimbursable costs was $17 million as of December 31, 2012, which has been recorded in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor's meters. PECO intends to move forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO's decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period's earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $19 million, net of approximately $16 million of reimbursements from the DOE. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO did not seek recovery of original meter costs in the January 2013 universal deployment filing, as resolution with the vendor is still pending. In November 2012, PECO requested and received approval from the DOE that the original meters continue to be allowable costs. In addition, PECO remains eligible for the full $200 million in SGIG funds.

As of December 31, 2012, PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As a result, a regulatory asset of $17 million, representing the cost of the original meters, net of accumulated depreciation and DOE reimbursements, was recorded on Exelon's and PECO's Consolidated Balance Sheets as of December 31, 2012. If PECO later determines that the regulatory asset is no longer probable of recovery, PECO would be required to recognize a charge in earnings in the period in which that determination was made.

Energy Efficiency Programs. PECO's PAPUC-approved Phase I EE&C Plan has a four-year term that began on June 1, 2009 and will conclude on May 31, 2013. Spending for Phase I totals more than $328 million pursuant to Act 129's EE&C reduction targets. The Phase I plan sets forth how PECO will meet the required reduction targets established by Act 129's EE&C provisions, which include a 3% reduction in electric consumption in PECO's service territory and a 4.5% reduction in PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013. If PECO fails to achieve the required reductions in consumption within the stated deadline, PECO will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers.

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.

On August 2, 2012, the PAPUC issued its Phase II EE&C implementation order. The order provides energy consumption reduction requirements for the second phase of Act 129's EE&C programs, which will go into effect on June 1, 2013, but defers a decision on peak demand reduction requirements until 2013. The order tentatively established PECO's three-year cumulative consumption reduction target at 2.9%. In August 2012, PECO requested an evidentiary hearing regarding the appropriateness of its 2.9% target. The target was subsequently reaffirmed by the PAPUC on December 5, 2012. In addition, on September 4, 2012, PECO filed a Petition for Reconsideration of the terms of the PAPUC's implementation order for Phase II, which was subsequently denied.

Pursuant to the Phase II implementation order, PECO filed its three-year EE&C Phase II plan with the PAPUC on November 1, 2012. The plan 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, adjusted for weather and extraordinary loads. The implementation order permits PECO to apply any excess savings achieved during Phase I against its Phase II consumption reduction targets, with no reduction to its Phase II budget. In accordance with the Act 129 Phase II implementation order, at least 10% and 4.5% of the total consumption reductions must be through programs directed toward PECO's public and low income sectors, respectively. If PECO fails to achieve the required reductions in consumption, it will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers. Act 129 mandates that the total cost of the plan may not exceed 2% of the electric company's total annual revenue as of December 31, 2006.

Alternative Energy Portfolio Standards. In November 2004, Pennsylvania adopted the AEPS Act. The AEPS Act mandated that beginning in 2011, following the expiration of PECO's rate cap transition period, certain percentages of electric energy sold to Pennsylvania retail electric customers shall be generated from certain alternative energy resources as measured in AECs. The requirement for electric energy that must come from Tier I alternative energy resources ranges from approximately 3.5% to 8% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10%. The required compliance percentages incrementally increase each annual compliance period, which is from June 1 through May 31, until May 31, 2021. These Tier I and Tier II alternative energy resources include acceptable energy sources as set forth in Act 129 and the AEPS Act.

PECO has entered into five-year and ten-year agreements with accepted bidders, including Generation, totaling 452,000 non-solar and 8,000 solar Tier I AECs annually in accordance with a PAPUC approved plan. The plan allowed PECO to bank AECs procured prior to 2011 and use the banked AECs to meet its AEPS Act obligations over two compliance years ending May 2013. The PAPUC also approved the procurement of Tier II AECs and supplemental AECs as well as the sale of excess AECs through independent third party auctions or brokers. On January 5, 2012, PECO successfully conducted a competitive procurement for 275,000 Tier II AECs to be available toward its AEPS Act obligations for its compliance years ended May 2012 and ending May 2013, which was approved by the PAPUC on January 17, 2012.

All AEPS administrative costs and costs of AECs incurred after December 31, 2010 are being recovered on a full and current basis from default service customers through a surcharge.

PECO's second DSP Program eliminated the AEPS rider. Beginning in June 2013, AEPS compliance costs will be recovered through the GSA.

Natural Gas Choice Supplier Tariff. During 2011, the PAPUC approved PECO's tariff supplements to its Gas Choice Supplier Coordination Tariff and its Retail Gas Service Tariff to address the new licensing requirements for natural gas suppliers (NGS) set forth in the PAPUC's final rulemaking order, which became effective January 1, 2011. The new licensing requirements broaden the types of collateral that PECO can require to mitigate its risk related to an NGS default, as well as PECO's ability to adjust collateral when material changes in supplier creditworthiness occur. PECO has completed its creditworthiness determinations and notified affected NGSs of their new collateral levels. As a result, PECO has obtained $14 million of collateral as of December 31, 2012.

Investigation of Pennsylvania Retail Electricity Market. On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania's retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO's second DSP Program, which includes several new programs to continue PECO's support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012. On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, which would allow for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities' aging electric and natural gas distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year rates are in effect. On August 2, 2012, the PAPUC issued a final order establishing rules and procedures to implement the ratemaking provisions of Act 11. The implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the Commission prior to implementing a DSIC. PECO filed its LTIIP for its Gas Operations on February 8, 2013 with the PAPUC.

Maryland Regulatory Matters

2011 Maryland Electric and Gas Distribution Rate Case. In March 2011, the MDPSC issued a comprehensive rate order setting forth the details of the decision contained in its abbreviated 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 that began 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 a regulated rate of return.

Smart Meter and Smart Grid Investments. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE's Smart Grid program. The ultimate resolution related to this feature could affect BGE's ability to demonstrate cost-effectiveness of the advanced metering system. Under a grant from the DOE, BGE is a recipient of $200 million in federal funding for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives. The project to install the smart meters began in late April 2012.

As of December 31, 2012, BGE had received $142 million in reimbursements from the DOE. As of December 31, 2012, BGE's outstanding receivable from the DOE for reimbursable costs was $15 million, which has been recorded in other accounts receivable, net on Exelon's and BGE's Consolidated Balance Sheets.

New Electric Generation. On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that the utilities pay (or receive) the difference between CPV's contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The three Maryland utilities are required to enter into a CfD in amounts proportionate to their relative SOS load as of the date of execution. Depending on the precise terms of the CfD, the eventual market conditions, and the manner of cost recovery, the CfD could have a material adverse impact on Exelon's and BGE's results of operations, cash flows and financial positions. On April 27, 2012, a civil complaint was filed in the United States District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on federal law grounds. Among other requests for relief, the plaintiffs seek to enjoin the MDPSC from executing or otherwise putting into effect any part of its order. The MDPSC and CPV filed motions to dismiss the federal lawsuit, which were both denied by the U.S. District Court on August 3, 2012. On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order. That petition was subsequently transferred to the Circuit Court for Baltimore City, where similar appeals have been filed by other interested parties. All cases have now been consolidated and will be heard together by the Circuit Court for Baltimore City in the first quarter of 2013.

2012 Maryland Electric and Gas Distribution Rate Case. On July 27, 2012, BGE filed an 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 and $45 million to its electric and gas base rates, respectively. The new electric and 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.

Dividend Restrictions. BGE pays dividends on its common stock after its Board of Directors declares them. However, BGE is subject to certain dividend restrictions established by the MDPSC. First, BGE is prohibited from paying a dividend on its common shares through the end of 2014. Second, BGE is prohibited from paying a dividend on its common shares if (a) after the dividend payment, BGE's equity ratio would be below 48% as calculated pursuant to the MDPSC's ratemaking precedents or (b) BGE's senior unsecured credit rating is rated by two of the three major credit rating agencies below investment grade. Finally, BGE must notify the MDPSC that it intends to declare a dividend on its common shares at least 30 days before such a dividend is paid.

Federal Regulatory Matters

Transmission Formula Rate. ComEd's and BGE's transmission rates are each established based on a FERC-approved formula.

ComEd's most recent annual formula rate update filed in May 2012 reflects actual 2011 expenses and investments plus forecasted 2012 capital additions. The update resulted in a revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. This compares to the May 2011 updated revenue requirement of $438 million offset by a $16 million reduction related to the reconciliation of 2010 actual costs for a net revenue requirement of $422 million. The increase in the revenue requirement was primarily driven by higher depreciation, pension and operating and maintenance costs, and the absence of a one-time credit that had been included in 2010 costs. The 2012 net revenue requirement became effective June 1, 2012, and is recovered over the period extending through May 31, 2013. The regulatory liability associated with the true-up is being amortized as the associated amounts are refunded.

ComEd's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.91%, a decrease from the 9.10% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd's long-term debt outstanding. As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE's most recent annual formula rate update, filed in April 2012, reflects actual 2011 expenses and investments plus forecasted 2012 capital additions on a weighted basis. This update resulted in a revenue requirement of $156 million plus an additional $2 million increase related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. This compares to the May 2011 updated net revenue requirement of $140 million. The increase in the revenue requirement is primarily driven by higher levels of capital investment and operating expenses. The 2012 net revenue requirement became effective June 1, 2012, and is recovered over the period extending through May 31, 2013. The regulatory asset associated with the 2011 revenue requirement true-up is being amortized as the associated amounts are collected from customers.

BGE's updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.43%, a decrease from the 8.96% return included in the update filed in April 2011. The decrease in return is primarily due to a reduced equity ratio and cost of debt at 2011 year-end compared to the previous year-end. BGE's formula rate includes an 11.3% rate of return on common equity for most investments included in its rate base.

PJM Transmission Rate Design and Operating Agreements. PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit. In April 2007, FERC issued an order concluding that PJM's current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC's order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On January 21, 2010, FERC issued an order establishing paper hearing procedures to supplement the record. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. A number of entities have filed requests for rehearing. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On January 31, 2013, FERC issued an order stating that the transmission owner filing is interdependent with PJM's October 25, 2012 Order No. 1000 filing and thus, while FERC accepted the cost allocation for filing, it did so subject to refund, and a further order at the time FERC issues an order on PJM's Order No. 1000 Compliance Filing.

ComEd, PECO and BGE are committed to the construction of transmission facilities under their operating agreements with PJM to maintain system reliability. ComEd, PECO and BGE will work with PJM to continue to evaluate the scope and timing of any required construction projects. ComEd, PECO and BGE's estimated commitments are as follows:

	Total	2013	2014	2015	2016	2017
ComEd	$525	$175	$86	$135	$128	$ 1
PECO	140	28	23	26	36	27
BGE	249	15	53	119	55	7

PJM Minimum Offer Price Rule. PJM's capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to the FERC's approval of the existing MOPR were extensive. The parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving the existing MOPR have been appealed to the Third Circuit Court of Appeals. A resolution of that appeal is not expected until sometime in 2013.

In May 2012, PJM announced the results of its capacity auction covering 2015 and 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, states will expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believes that further revisions to the MOPR are necessary to ensure that the potential to reduce artificially capacity auction prices is appropriately limited in PJM. In late December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believes will be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which the MOPR changes were developed, supports the changes and intends to continue to work with PJM and its stakeholders to obtain necessary approvals. On February 5, 2013, the FERC issued a letter finding that PJM's new MOPR filing is deficient and requested that PJM provide additional information on several aspects of PJM's MOPR proposal. PJM has 30 days to respond, and a FERC decision is expected within 60 days thereafter.

Market-Based Rates. Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC's acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC's regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE have filed market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy and capacity under market-based rate tariffs. FERC accepted the 2008 filings on September 16, 2008, January 15, 2009 and September 2, 2009 and accepted the 2009 filings on July 28, 2009, October 26, 2009, February 23, 2010 and April 30, 2010, affirming Exelon's affiliates continued right to make sales at market-based rates. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. The most recent updated analysis for the PJM and Northeast Regions was filed in late 2010, based on 2009 historic test period data. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, based on Generation's most recent updated analysis filed in 2010, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation programs. Similarly, on June 29, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012, and on December 23, 2011, Generation filed its updated market power analysis for the Southeast Region which the FERC accepted on October 10, 2012. On December 21, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the SPP region, and the FERC has not yet acted on this filing.

Reliability Pricing Model. PJM's RPM auctions take place 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2016 occurred in May 2012.

License Renewals. On April 8, 2009, the NRC issued a renewed operating license for Oyster Creek that expires in April 2029. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

On June 30, 2011, the NRC issued the renewed operating licenses for Salem Units 1 and 2 expiring in 2036 and 2040, respectively. Exelon is a 42.59% owner of the Salem Units.

On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States District Court of Appeals for the DC Circuit vacated the NRC's temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the "waste confidence decision") recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court's decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule through rulemaking no later than September 6, 2014. Generation does not expect the NRC to issue license renewals until September 2014, at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project and the Muddy Run Pumped Storage Facility Project, respectively. The FERC review process is expected to be completed by August 31, 2014, when the current Conowingo license expires.

Regulatory Assets and Liabilities

Exelon prepares its consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

The following tables provide information about the regulatory assets and liabilities of Exelon as of December 31, 2012 and 2011. Upon consummation of the merger, Exelon reclassified certain regulatory asset and liability balances as of December 31, 2011 in order to align the reporting of the regulated utilities.

	December 31, 2012	
	Current	Noncurrent
Regulatory assets		
Pension and other postretirement benefits	$304	$3,673
Deferred income taxes	14	1,382
AMI programs	3	70
AMI meter events	—	17
Under-recovered distribution service costs	18	191
Debt costs	14	68
Fair value of BGE long-term debt (a)	—	256
Fair value of BGE supply contract (b)	77	12
Severance	29	28
Asset retirement obligations	—	90
MGP remediation costs	58	232
RTO start-up costs	3	2
Under-recovered electric universal service fund costs	11	—
Financial swap with Generation	—	—
Renewable energy and associated RECs	18	49
Under-recovered energy and transmission costs	43	—
DSP Program costs	1	3
DSP II Program costs	1	2
Deferred storm costs	3	6
Electric generation-related regulatory asset	16	40
Rate stabilization deferral	67	225
Energy efficiency and demand response programs	56	126
Other	23	25
Total regulatory assets	$759	6,497

(a) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date. See Note 4—Merger and Acquisitions for additional information.
(b) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE's supply contracts as of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved regulated rates. See Note 4—Merger and Acquisitions for additional information.

	December 31, 2012	
	Current	Noncurrent
Regulatory liabilities		
Nuclear decommissioning	$—	$2,397
Removal costs	97	1,406
Energy efficiency and demand response programs	131	—
Electric distribution tax repairs	20	132
Gas distribution tax repairs	8	46
Over-recovered uncollectible accounts	6	—
Over-recovered energy and transmission costs	54	—
Over-recovered gas universal service fund costs	3	—
Over-recovered AEPS costs	2	—
Total regulatory liabilities	$321	$3,981

	December 31, 2011	
	Current	Noncurrent
Regulatory assets		
Pension and other postretirement benefits	$204	$2,794
Deferred income taxes	5	1,176
AMI and smart meter programs	2	28
Under-recovered distribution service costs	14	70
Debt costs	18	81
Severance	25	38
Asset retirement obligations	—	74
MGP remediation costs	30	129
RTO start-up costs	3	4
Under-recovered electric universal service fund costs	3	—
Financial swap with Generation	—	—
Renewable energy and associated RECs	9	97
Under-recovered energy and transmission costs	57	—
DSP Program costs	3	2
Deferred storm costs	—	—
Electric generation-related regulatory asset	—	—
Rate stabilization deferral	—	—
Energy efficiency and demand response programs	—	—
Other	17	25
Total regulatory assets	$390	$4,518

	December 31, 2011	
	Current	Noncurrent
Regulatory liabilities		
Nuclear decommissioning	$—	$2,222
Removal costs	61	1,185
Energy efficiency and demand response programs	49	69
Electric distribution tax repairs	19	151
Over-recovered uncollectible accounts	15	—
Over-recovered energy and transmission costs	42	—
Over-recovered gas universal service fund costs	3	—
Over-recovered AEPS costs	8	—
Other	—	—
Total regulatory liabilities	$197	$3,627

Pension and other postretirement benefits. As of December 31, 2012, Exelon recorded regulatory assets of $3,977 million related to ComEd's and BGE's portion of deferred costs associated with Exelon's pension plans and ComEd's, PECO's and BGE's portion of deferred costs associated with Exelon's other postretirement benefit plans. PECO's pension regulatory recovery is based on cash contributions and is not included in the regulatory asset balance. The regulatory asset is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses attributable to Exelon's pension and other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd, PECO and BGE will recover these costs through base rates as allowed in their most recently approved regulated rate orders. The pension and other postretirement benefit regulatory asset balance includes a regulatory asset established at the date of the merger related to BGE's portion of the deferred costs associated with legacy Constellation's pension and other postretirement benefit plans. That BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger. See Note 14—Retirement Benefits for additional detail. No return is earned on Exelon's regulatory asset.

Deferred income taxes. These costs represent the difference between the method by which the regulator allows for the recovery of income taxes and how income taxes would be recorded under GAAP. Regulatory assets and liabilities associated with deferred income taxes, recorded in compliance with the authoritative guidance for accounting for certain types of regulation and income taxes, include the deferred tax effects associated principally with liberalized depreciation accounted for in accordance with the ratemaking policies of the ICC, PAPUC and MDPSC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd and BGE, this amount includes the impacts of a reduction in the deductibility, for Federal income tax purposes, of certain retiree health care costs pursuant to the March 2010 Health Care Reform Acts. ComEd was granted recovery of these additional income taxes on May 24, 2011 in the ICC's 2010 Rate Case order. The recovery period for these costs is through May 31, 2014. For BGE, these additional income taxes are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. See Note 12—Income Taxes and Note 14—Retirement Benefits for additional information. ComEd, PECO and BGE are not earning a return on the regulatory asset in base rates.

AMI programs. For ComEd, this amount represents operating and maintenance expenses and meter costs associated with ComEd's AMI pilot program approved in the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods for operating and maintenance expenses and meter costs are through May 31, 2014, and January 1, 2020, respectively. In addition, ComEd recorded approximately $7 million of accelerated depreciation costs resulting from the early retirements of non-AMI meters as a regulatory asset beginning during the fourth quarter of 2012, which will be amortized over an average ten year period pursuant to the ICC approved AMI Deployment plan. ComEd is earning a return on the meter costs. For PECO, this amount represents accelerated depreciation and filing and implementation costs relating to the PAPUC-approved Smart Meter Procurement and Installation Plan as well as the return on the un-depreciated investment, taxes, and operating and maintenance expenses. The approved plan allows for recovery of filing and implementation costs incurred through December 31, 2010 during 2011 and 2012. In addition, the approved plan provides for recovery of program costs, which includes depreciation on new equipment placed in service, beginning in January 2011 on full and current basis, which includes interest income or expense on the under or over recovery. The approved plan also provides for recovery of accelerated depreciation on PECO's non-AMI meter assets over a 10-year period ending December 31, 2020. For BGE, this amount represents smart grid pilot program costs as well as the incremental costs associated with implementing full deployment of a smart grid program. Pursuant to a MDPSC order, pilot program costs of $11 million were deferred in a regulatory asset, and, beginning with the MDPSC's March 2011 rate order, is earning BGE's most current authorized rate of return. In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE, authorizing BGE to establish a separate regulatory asset for incremental costs incurred to implement the initiative, including the net depreciation and amortization costs associated with the meters, and an authorized rate of return on these costs, a portion of which is not recognized under GAAP until cost recovery begins. Additionally, the MDPSC order requires that BGE prove the cost-effectiveness of the entire smart grid initiative prior to seeking recovery of the costs deferred in these regulatory assets. Therefore, the commencement and timing of the amortization of these deferred costs is currently unknown. BGE's AMI regulatory asset excludes costs for non-AMI meters being replaced by AMI meters, as the MDPSC has ordered that the cost recovery for non-AMI meters will be considered in a future depreciation proceeding.

AMI Meter Events. This amount represents the cost value of the original smart meters, net of accumulated depreciation and DOE reimbursements, purchased for the first phase of smart meter deployment that will no longer be used, including installation and removal costs. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As such, PECO has deferred these costs on Exelon's and PECO's Consolidated Balance Sheet. PECO will not earn a return on the recovery of these costs.

Under-recovered distribution services costs. Under EIMA, which became effective in the fourth quarter of 2011, ComEd is allowed recovery of distribution services costs through a formula rate tariff. The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs that the ICC determines are prudently and reasonably incurred in a given year. The reconciliation will be recovered through rates over a one-year period, beginning in January 2013 for the 2011 annual reconciliation period. The regulatory asset also includes costs associated with certain one-time events, such as large storms, which will be recovered over a five-year period beginning in January 2013. ComEd is earning a return on these costs. As of December 31, 2012, the regulatory asset was comprised of $125 million for the annual reconciliation and $84 million related to significant one-time events. In addition to $58 million in deferred storm costs, net of amortization, the December 31, 2012 balance related to significant one-time events contains $26 million of merger and integration related costs, net of amortization, incurred as a result of the merger. As of December 31, 2012, ComEd and BGE recorded regulatory assets of $5 million and $1 million, respectively, in other regulatory assets for merger and integration-related costs. See Note 4—Mergers and Acquisitions for additional information.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's, PECO's and BGE's recoverable losses on reacquired long-term debt related to regulated operations are deferred and amortized to interest expense over the life of the new debt issued to finance the debt redemption or over the life of the original debt issuance if the debt is not refinanced. Interest-rate swap settlements are deferred and amortized over the period that the related debt is outstanding or the life of the original issuance retired. These debt costs are used in the determination of the weighted cost of capital applied to rate base in the rate-making process. ComEd and BGE are not earning a return on the recovery of these costs.

Severance. For ComEd, these costs represent previously incurred severance costs that ComEd was granted recovery of in the December 20, 2006, ICC rehearing rate order and the May 24, 2011, ICC order in ComEd's 2010 rate case. The recovery periods are through June 30, 2014, and May 31, 2014, respectively. ComEd is not earning a return on these costs. For BGE, these costs represent deferred severance costs that BGE has either previously been granted recovery of in rates or has requested recovery in a current rate case. Costs include the portion of costs associated with a 2008 workforce reduction that relate to BGE's gas business which were deferred in 2009 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in January 2009. Also included are costs associated with a 2010 workforce reduction that were deferred as a regulatory asset and are being amortized over a 5-year period that began in March 2011 in accordance with the MDPSC's March 2011 rate order. Finally, costs associated with the 2012 BGE voluntary workforce reduction were deferred in 2012 as a regulatory asset in accordance with the MDPSC's orders in prior rate cases and are being amortized over a 5-year period that began in July 2012. BGE is earning a regulated return on the regulatory asset included in base rates.

Asset retirement obligations. These costs represent future removal costs associated with ComEd's and PECO's existing asset retirement obligations. PECO will begin to earn a return on, and a recovery of, these costs once the removal activities have been performed. ComEd will recover these costs through future depreciation expense and will earn a return on these costs once the removal activities have been performed. See Note 13—Asset Retirement Obligations for additional information.

MGP remediation costs. Recovery of these items was granted to ComEd in the July 26, 2006, ICC rate order. For PECO, these costs are recoverable through rates as affirmed in the 2010 approved natural gas distribution rate case settlement. 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 period of recovery for both ComEd and PECO will depend on the timing of the actual expenditures. ComEd and PECO are not earning a return on the recovery of these costs. For BGE, $5 million of clean-up costs incurred during the period from July 2000 through November 2005 and an additional $1 million from December 2005 through November 2010 are recoverable through rates in accordance with MDPSC orders. These costs are being amortized over 10-year periods that began in January 2006 and December 2010, respectively. BGE is earning a regulated return on the regulatory asset included in base rates. See Note 19—Commitments and Contingencies for additional information.

RTO start-up costs. Recovery of these RTO start-up costs was approved by FERC. The recovery period is through March 31, 2015. ComEd is earning a return on these costs.

Under (Over)-recovered universal service fund costs. The universal service fund cost is a recovery mechanism that allows PECO to recover discounts issued to electric and gas customers enrolled in assistance programs. As of December 31, 2012, PECO was under-recovered for its electric program and over-recovered for its gas program. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Financial swap with Generation. To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five-year financial swap contract with Generation that expires on May 31, 2013. Since the swap contract was deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period are recorded by ComEd as well as an offsetting regulatory asset or liability. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price. In Exelon's consolidated financial statements, the fair value of the intercompany swap recorded by Generation and ComEd is eliminated.

Renewable Energy and Associated RECs. On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Since the swap contracts were deemed prudent by the Illinois Settlement Legislation, ensuring ComEd of full recovery in rates, the changes in fair value each period as well as an offsetting regulatory asset or liability are recorded by ComEd. ComEd does not earn (pay) a return on the regulatory asset (liability). The basis for the mark-to-market derivative asset or liability position is based on the difference between ComEd's cost to purchase energy on the spot market and the contracted price.

Under (Over)-recovered energy and transmission costs. Starting in 2007, ComEd's energy and transmission costs are recoverable (refundable) under ComEd's ICC and/or FERC-approved rates. ComEd earns interest on under-recovered costs and pays interest on over-recovered costs to customers. The PECO energy costs represent the electric and gas supply related costs recoverable (refundable) under PECO's GSA and PGC, respectively. PECO earns interest on the under-recovered energy and natural gas costs and pays interest on over-recovered energy and natural gas costs to customers. The PECO transmission costs represent the electric transmission costs recoverable (refundable) under the TSC under which PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers. As of December 31, 2012, PECO had a regulatory asset related to under-recovered electric transmission costs of $1 million and a regulatory liability that included $47 million related to over-recovered electric supply costs under the GSA and $1 million related to over-recovered natural gas supply costs under the PGC. As of December 31, 2011, PECO had a regulatory asset related to under-recovered transmission costs of $9 million and a regulatory liability that included $25 million related to over-recovered electric supply costs under the GSA and $5 million related to over-recovered natural gas supply costs under the PGC. The BGE energy costs represent the electric and gas supply related costs recoverable (refundable) from (to) customers under BGE's market-based SOS and MBR programs, respectively. BGE does not earn or pay interest on under- or over-recovered costs to customers. See "ITEM 1. BUSINESS—BGE" for further details on BGE's market-based SOS and MBR programs. As of December 31, 2012, BGE had a regulatory asset that included $9 million related to under-recovered electric supply costs and $19 million related to under-recovered natural gas supply costs.

DSP Program costs. These amounts represent recoverable administrative costs incurred relating to filing, procurement, and information technology improvements associated with PECO's PAPUC-approved DSP Program for the procurement of electric supply following the expiration of PECO's generation rate caps on December 31, 2010. The filing and implementation costs of this DSP Program are recoverable through the GSA over its 29-month term, beginning January 1, 2011. The independent evaluator costs associated with conducting procurements is recoverable over a 12-month period after the PAPUC approves the results of the procurements. Costs relating to information technology improvements are recoverable over a 5-year period beginning January 1, 2011. PECO earns a return on the recovery of information technology costs.

DSP II Program Costs. These amounts represent recoverable administrative costs incurred relating to the filing and procurement associated with PECO's second PAPUC-approved DSP program for the procurement of electric supply. The filing and procurement of this DSP Program are recoverable through the GSA over its 24-month term, beginning June 1, 2013. The independent evaluator costs associated with conducting procurements are recoverable over a 12-month period after the PAPUC approves the results of the procurements. PECO is not earning a return on these costs.

Deferred storm costs. In the MDPSC's March 2011 rate order, BGE was authorized to defer $16 million in storm costs incurred in February 2010. These costs are being amortized over a 5-year period that began in December 2010. BGE is earning a regulated return on the regulatory asset included in base rates.

Electric generation-related regulatory asset. As a result of the deregulation of electric generation, BGE ceased to meet the requirements for accounting for a regulated business for the previous electric generation portion of its business. As a result, BGE wrote-off its entire individual, generation-related regulatory assets and liabilities and established a single, generation-related regulatory asset to be collected through its regulated rates, which is being amortized on a basis that approximates the pre-existing individual regulatory asset amortization schedules. A portion of this regulatory asset represents income taxes recoverable through future rates that do not earn a regulated rate of return. These amounts were $47 million as of December 31, 2012, and $56 million as of December 31, 2011. BGE will continue to amortize this amount through 2017.

Rate stabilization deferral. In June 2006, Senate Bill 1 was enacted in Maryland and imposed a rate stabilization measure that capped rate increases by BGE for residential electric customers at 15% from July 1, 2006, to May 31, 2007. As a result, BGE recorded a regulatory asset on its Consolidated Balance Sheets equal to the difference between the costs to purchase power and the revenues collected from customers, as well as related carrying charges based on short-term interest rates from July 1, 2006, to May 31, 2007. In addition, as required by Senate Bill 1, the MDPSC approved a plan that allowed residential electric customers the option to further defer the transition to market rates from June 1, 2007, to January 1, 2008. During 2007, BGE deferred $306 million of electricity purchased for resale expenses and certain applicable carrying charges, which are calculated using the implied interest rates of the rate stabilization bonds, as a regulatory asset related to the rate stabilization plans. During 2012 and 2011, BGE recovered $67 million and $57 million, respectively, of electricity purchased for resale expenses and carrying charges related to the rate stabilization plan regulatory asset. BGE began amortizing the regulatory asset associated with the deferral which ended in May 2007 to earnings over a period not to exceed ten years when collection from customers began in June 2007.

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan, PECO's PAPUC-approved EE&C Plan, and BGE's Smart Energy Savers Program®. ComEd began recovering these costs or refunding over-collections of these costs on June 1, 2008 through a rider. ComEd earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. PECO began recovering these costs through a rider in January 2010 based on projected spending under the program. Recovery will continue over the life of the program, which expires on May 31, 2013. Excess funds collected are required to be refunded no later than June 30, 2013. PECO earns a return on the capital investment incurred under the program but does not earn (pay) interest on under (over) collections. BGE's Smart Energy Savers Program® includes both MDPSC approved demand response and energy efficiency programs. For the BGE demand response program which began in January 2008, actual marketing and customer bonus costs incurred in the demand response program are being recovered over a 5-year amortization period from the date incurred pursuant to an order by the MDPSC. Fixed assets related to the demand response program are recovered over the life of the equipment. Actual costs incurred in the conservation program are being amortized over a 5- year period with recovery beginning in 2010 pursuant to an order by the MDPSC. BGE earns a regulated rate of return on the capital investments and deferred costs incurred under the program and earns (pays) interest on under (over) collections.

Rate case costs. The ICC generally allows ComEd to receive recovery of rate case costs over three years. The ICC has issued orders allowing recovery of these costs on July 26, 2006, September 10, 2008, and May 24, 2011. The recovery period for the two former rate case costs was through September 15, 2011. The recovery period for the 2010 Rate Case costs is through May 31, 2014. Pursuant to the approved settlements of the 2010 electric and natural gas distribution rate cases, PECO is allowed recovery of rate case costs over two years ended December 31, 2012. ComEd and PECO do not earn a return on the recovery of these costs.

Nuclear decommissioning. These amounts represent estimated future nuclear decommissioning costs that exceed (regulatory asset) or are less than (regulatory liability) the associated decommissioning trust fund assets. Exelon believes the trust fund assets, including prospective earnings thereon and any future collections from customers, will equal the associated future decommissioning costs at the time of decommissioning. See Note 13—Asset Retirement Obligations for additional information.

Removal costs. These amounts represent funds ComEd and BGE have received from customers to cover the future removal of property, plant and equipment which reduces rate base for ratemaking purposes.

Electric distribution tax repairs. PECO's 2010 electric distribution rate case settlement required that the expected cash benefit from the application of Revenue Procedure 2011-43, which was issued on August 19, 2011, to prior tax years be refunded to customers over a seven-year period. Credits began being reflected in customer bills on January 1, 2012. No interest will be paid to customers.

Gas distribution tax repairs. PECO's 2010 natural gas distribution rate case settlement required that the expected cash benefit from the application of new tax repairs deduction methodologies for 2010 and prior tax years be refunded to customers over a seven-year period. In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. Credits will be reflected in customer bills beginning January 1, 2013. No interest will be paid to customers.

Under (Over)-recovered uncollectible accounts. As a result of the February 2010 ICC order approving recovery of ComEd's uncollectible accounts, ComEd has the ability to adjust its rates annually to reflect the increases and decreases in annual uncollectible accounts expense starting with year 2008. ComEd recorded a regulatory asset for the cumulative under-collections in 2008 and 2009. Recovery of the initial regulatory asset was completed over an approximate 14-month time frame which began in April 2010. The recovery or refund of the difference in the uncollectible accounts expense applicable to the years starting with January 1, 2010, will take place over a 12-month time frame beginning in June of the following year. ComEd is not earning a return on these costs.

Under (Over)-recovered AEPS costs current asset (liability). The AEPS costs represent the administrative and AEC costs incurred to comply with the requirements of the AEPS Act, which are recoverable on a full and current basis. PECO earns interest on under-recovered costs and pays interest on over-recovered costs to customers.

Purchase of Receivables Programs

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities' consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through distribution rates. Exelon, ComEd, PECO, and BGE do not record unbilled commodity receivables under their POR programs. Purchased billed receivables are classified in other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of Exelon as of December 31, 2012 and 2011.

As of December 31, 2012	
Purchased receivables [(a)]	$191
Allowance for uncollectible accounts [(b)]	(21)
Purchased receivables, net	$170

As of December 31, 2011	
Purchased receivables [(a)]	$ 68
Allowance for uncollectible accounts [(b)]	(5)
Purchased receivables, net	$ 63

(a) PECO's gas POR program became effective on January 1, 2012 and includes a 1% discount on purchased receivables in order to recover the implementation costs of the program. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

(b) Reflects ComEd's incremental allowance for uncollectible accounts recorded, which is in addition to the purchase discount. For ComEd, the incremental uncollectible accounts expense is recovered through its Purchase of Receivables with Consolidated Billing (PORCB) tariff.

4. Merger and Acquisitions

Merger with Constellation

Description of Transaction

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

Constellation's shareholders received 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock outstanding as of March 12, 2012. Generally, all outstanding Constellation equity-based compensation awards were converted into Exelon equity-based compensation awards using the same ratio. See Note 17—Common Stock for further information.

Regulatory Matters

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that were pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion.

On February 17, 2012, the MDPSC approved the merger with conditions. Many of the conditions were reflective of the settlement agreements described above. The following costs were recognized after the closing of the merger and are included in Exelon's Consolidated Statement of Operations and Comprehensive Income for the year ended December 31, 2012:

Description	Payment Period	Exelon	Statement of Operations Location
BGE rate credit of $100 per residential customer [a]	Q2 2012	$ 113	Revenues
Customer investment fund to invest in energy efficiency and low-income energy assistance to BGE customers	2012 to 2014	113.5	O&M Expense
Contribution for renewable energy, energy efficiency or related projects in Baltimore	2012 to 2014	2	O&M Expense
Charitable contributions at $7 million per year for 10 years	2012 to 2021	70	O&M Expense
State funding for offshore wind development projects	Q2 2012	32	O&M Expense
Miscellaneous tax benefits	Q2 2012	(2)	Taxes Other Than Income
Total		$328.5	

(a) Exelon made a $66 million equity contribution to BGE in the second quarter of 2012 to fund the after-tax amount of the rate credit as directed in the MDPSC order approving the merger transaction.

In addition to these costs, the direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. The construction is expected to be completed in 1 to 2 years. The estimate also includes $625 million for Exelon's and Generation's commitment to develop or assist in the development of 285—300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of December 31, 2012, amounts reflected in the Exelon and Generation consolidated financial statements for these commitments were immaterial.

The settlement agreement contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets, and therefore will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of December 31, 2012, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

Pursuant to the MDPSC merger approval conditions, BGE is restricted from paying any dividend on its common shares through the end of 2014, is required to maintain specified minimum capital and O&M expenditure levels in 2012 and 2013, and is not permitted to reduce employment levels due to involuntary attrition associated with the merger integration process.

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 located in PJM within 150 days (subsequently extended 30 days by the DOJ) following the merger completion and to complete the divestitures within 30 days after receipt of regulatory approvals. These stations, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, include base-load, coal-fired generation units plus associated gas/oil units located at the same sites, and total 2,648 MW of generation capacity.

On August 8, 2012, a subsidiary of Generation reached an agreement to sell these three Maryland generating stations and associated assets to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. The sale was completed on November 30, 2012. The sale agreement included a base price with purchase price adjustments based on fuel inventory, working capital, capital expenditures, and timing of the closing, resulting in net proceeds from the sale of approximately $371 million. Decisions by certain market participants to remove themselves from the bidding process, combined with the deadlines and limitations on the pool of potential buyers imposed by the merger approval orders, resulted in realized sales proceeds below Generation's estimated fair value of the Maryland generating stations. Consequently, Exelon and Generation recorded a pre-tax loss of $278 million in operating and maintenance expense in the third quarter of 2012 to reflect the difference between the estimated sales price at that time and carrying value. This loss amount was adjusted to $272 million to reflect the final sales price upon closing on November 30, 2012.

In connection with the sale of the Maryland generating stations, Exelon agreed to indemnify Raven Power for certain costs associated with the treatment of hazardous substances at off-site disposal facilities and any claims arising as a result of, or in connection with, any toxic tort, natural resource damages, loss of life or injury to persons due to releases of, or exposure to hazardous substances in connection with Raven Power's remediation of environmental contamination or Exelon's non-compliance with environmental laws or permits prior to the closing date of the sale.

Subsequent to the merger, Generation discovered that, for the first two weeks following the merger, due to a software error, Generation inadvertently bid certain generating units into the PJM energy market at prices that slightly exceeded the cost-based caps to which it had agreed. This error was a violation of the commitments made in connection with merger approvals by DOJ, FERC and the MDPSC. Generation reported the error to the DOJ, FERC and the MDPSC and committed to remedy the impacts of its error. The MDPSC held a hearing to review the error, and accepted Generation's proposed remediation. Subsequent close examination by Generation of its cost-based bids also revealed the need for some minor adjustments to the cost build up for certain of its PJM units. Generation has coordinated with PJM to determine the impact on Generation's revenues and the market from this error and these adjustments, and Generation has worked with PJM to reverse the financial impacts. In November 2012, Generation reached a settlement with the DOJ regarding this matter. The final resolution did not have a material impact on Exelon's or Generation's results of operations, cash flows or financial position.

In addition, in January 2012, Exelon and Constellation reached an agreement with EDF under which EDF withdrew its opposition to the Exelon-Constellation merger. The terms of the agreement address CENG, a joint venture between Constellation and EDF that owns and operates a total of three nuclear facilities with a total of five generating units in Maryland and New York. The agreement reaffirms the terms of the joint venture. The agreement did not include any exchange of monetary consideration, and Exelon does not expect the agreement will have a material effect on Exelon's and Generation's future results of operations, financial position and cash flows.

Exelon was named in suits filed in the Circuit Court of Baltimore City, Maryland alleging that individual directors of Constellation breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. Similar suits were also filed in the United States District Court for the District of Maryland. The suits sought to enjoin a Constellation shareholder vote on the proposed merger until all material information was disclosed and sought rescission of the proposed merger. During the third quarter of 2011, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. On June 26, 2012, the court approved the settlement and entered final judgment.

Accounting for the Merger Transaction

The total consideration in the merger was based on the opening price of a share of Exelon common stock on March 12, 2012 (in millions):

	Number of Shares/ Awards Issued	Total Fair Value
Issuance of Exelon common stock to Constellation shareholders and equity award holders at the exchange ratio of 0.930 shares for each share of Constellation common stock; based on the opening price of Exelon common stock on March 12, 2012 of $38.91 [(a)]	187.45	$7,294
Issuance of Exelon equity awards to replace existing Constellation equity awards [(b)]	11.30	71
Total purchase price		$7,365

(a) The number of shares issued excludes 0.7 million shares of stock that are held in a custodian account specifically for the settlement of unvested share-based restricted stock awards. The related share value is excluded from the estimated fair value as these awards have not vested and, therefore, are not in the purchase price.

(b) Includes vested Constellation stock options and restricted stock units converted at fair value to Exelon awards on March 12, 2012. The fair value of the stock options was determined using the Black-Scholes model.

All options to purchase Constellation common stock under various equity agreements were converted into options to acquire a number of shares of Exelon common stock (as adjusted for the exchange ratio) at an option price. All Constellation unvested restricted stock awards granted prior to April 28, 2011, that were outstanding immediately prior to the consummation of the Merger, became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and converted into Exelon common stock at the exchange ratio in accordance with the applicable stock plan and award agreement terms. All Constellation restricted stock awards that remained unvested on a pro rata basis pursuant to the foregoing formula, and any Constellation unvested restricted stock awards granted after April 28, 2011, have been assumed by Exelon and automatically converted into shares of unvested restricted stock of Exelon at the exchange ratio. Likewise, all restricted stock units granted prior to April 28, 2011 under the Constellation Plans and outstanding immediately prior to the completion of the Initial Merger became vested on a pro rata basis (determined based upon the number of months from the start of the applicable restricted period to the closing of the Initial Merger) and have been assumed by Exelon and automatically converted into a number of shares of Exelon common stock at the exchange ratio.

The fair value of Constellation's non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE's tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE's debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE's assets acquired and liabilities assumed is recorded as a regulatory asset at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1—Significant Accounting Policies for additional information on BGE's push-down accounting treatment. Also see Note 3 – Regulatory Matters for additional information on BGE's regulatory assets.

The valuations performed in the first quarter of 2012 to assess the fair values of certain assets acquired and liabilities assumed were considered preliminary as a result of the short time period between the closing of the merger and the end of the first quarter of 2012. The allocation of the purchase price may be modified up to one year from the date of the merger as more information is obtained about the fair value of assets acquired and liabilities assumed. The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. The preliminary amounts recognized are subject to further revision until the valuations are completed and to the extent that additional information is obtained about the facts and circumstances that existed as of the merger date. Any changes to the fair value assessments may affect the purchase price allocation and material changes could require the financial statements to be retroactively amended.

The updated preliminary purchase price allocation of the Initial Merger of Exelon with Constellation at December 31, 2012 was as follows:

Preliminary Purchase Price Allocation, excluding amortization	
Current assets	$ 4,936
Property, plant and equipment	9,342
Unamortized energy contracts	3,218
Other intangibles, trade name and retail relationships	457
Investment in affiliates	1,942
Pension and OPEB regulatory asset	740
Other assets	2,265
Total assets	22,900
Current liabilities	3,408
Unamortized energy contracts	1,722
Long-term debt, including current maturities	5,632
Noncontrolling interest	90
Deferred credits and other liabilities and preferred securities	4,683
Total liabilities, preferred securities and noncontrolling interest	15,535
Total purchase price	$ 7,365

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The valuation of the acquired intangible assets and liabilities was estimated by applying either the market approach or the income approach depending on the nature of the underlying contract. The market approach was utilized when prices and other relevant information generated by market transactions involving comparable transactions were available. Otherwise the income approach, which is based upon discounted projected future cash flows associated with the underlying contracts, was utilized. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key estimates and inputs include forecasted power and fuel prices and the discount rate. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Exelon presents separately in its Consolidated Balance Sheet the unamortized energy contract assets and liabilities for these contracts. Exelon's amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $1,098 million. This amortization expense excludes the $116 million in amortization of the regulatory asset and equally offsetting amortization of the fuel supply contract liability recorded at Exelon Corporate in the Consolidated Statement of Operations. The weighted-average amortization period is approximately 1.5 years.

The fair value of the Constellation trade name intangible asset was determined based on the relief from royalty method of the income approach whereby fair value is determined to be the present value of the license fees avoided by owning the assets. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the hypothetical royalty rate and the discount rate. Exelon's and Generation's straight line amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $20 million. The amortization period is approximately 10 years. The trade name intangible asset is included in deferred debits and other assets within Exelon's Consolidated Balance Sheet.

The fair value of the retail relationships was determined based on a "multi-period excess method" of the income approach. Under this method, the intangible asset's fair value is determined to be the estimated future cash flows that will be earned on the current customer base, taking into account expected contract renewals based on customer attrition rates and costs to retain those customers. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. Key assumptions include the customer attrition rate and the discount rate. The intangible assets are amortized as amortization expense on a straight line basis over the useful life of the underlying assets averaging approximately 12.4 years. Exelon's amortization expense for the period March 12, 2012 to December 31, 2012 amounted to $15 million. The retail relationships intangible assets are included in deferred debits and other assets within Exelon's Consolidated Balance Sheet.

Exelon's intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of December 31, 2012:

					Estimated amortization expense					
Description	**Weighted Average Amortization**	**Gross**	**Accumulated Amortization**	**Net**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and Beyond**
Unamortized energy contracts, net [(a)]	1.5	$1,496	$ (982)	$514	$394	$ 74	$19	$(31)	$(22)	$ 80
Trade name	10.0	243	(20)	223	24	24	24	24	24	103
Retail relationships	12.4	214	(15)	199	19	19	19	19	19	104
Total, net		$1,953	$(1,017)	$936	$437	$117	$62	$ 12	$ 21	$287

(a) Includes the fair value of BGE's power and gas supply contracts for which an offsetting Exelon Corporate regulatory asset was also recorded.

Impact of Merger

It is impracticable to determine the current quarter and year-to-date overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation's operations and are therefore not fully distinguishable after the merger.

The impact of BGE on Exelon's Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $2,091 million and net loss of $31 million during the year ended December 31, 2012.

During the year ended December 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $746 million, $340 million, $5 million, $17 million and $160 million, respectively. These amounts do not include merger and integration-related costs of $36 million and $22 million incurred at ComEd and BGE, respectively, which have been recorded as a regulatory asset. The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for the year ended December 31, 2012.

During the year ended December 31, 2011, Exelon, Generation and PECO incurred merger and integration-related costs of $77 million, $15 million and $2 million, respectively. These costs are classified primarily within Operating and Maintenance Expense in the Registrants' respective Consolidated Statements of Operations and Comprehensive Income.

Severance Costs

Exelon has an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. Exelon records a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), Exelon measures the obligation and records the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process; as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. The amount of severance expense associated with the post-merger integration recognized through December 31, 2012, for Exelon is $138 million, which includes $88 million, $16 million, $7 million and $19 million for Generation, ComEd, PECO and BGE, respectively. Estimated costs to be incurred after December 31, 2012 are not material. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits. See Note 14—Retirement Benefits for additional information on the contractual termination benefits.

For the year ended December 31, 2012, the Registrants recorded the following severance benefits costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for ComEd and BGE:

Severance Benefits [(a)]	**Year Ended December 31, 2012**
Severance charges	$124
Stock compensation	7
Other charges	7
Total severance benefits	$138

(a) The amounts above include $46 million at Generation, $14 million at ComEd, $7 million at PECO, and $7 million at BGE, for amounts billed by BSC through intercompany allocations for the year ended December 31, 2012.

Amounts included in the table below represent the severance liability recorded by the Registrants for employees of the Registrants and exclude amounts billed through intercompany allocations:

Severance liability	**Year Ended December 31, 2012**
Balance at December 31, 2011	$—
Severance charges [(a)]	124
Stock compensation	7
Other charges [(b)]	7
Payments	(27)
Balance at December 31, 2012	$111

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits. Amounts also include one-time termination benefits of $3 million and $1 million for Exelon and Generation, respectively, which they began to recognize in the second quarter of 2012.
(b) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon's accounting policies and adjusting Constellation's, including BGE's as appropriate, results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Year Ended December 31,	
(unaudited)	**2012**	**2011 (a)**
Total Revenues	$26,700	$30,712
Net income attributable to Exelon	2,092	974
Basic Earnings Per Share	$ 2.56	$ 1.15
Diluted Earnings Per Share	2.55	1.14

(a) The amounts above include non-recurring costs directly related to the merger of $236 million for the year ended December 31, 2011.

Acquisitions

Consistent with the applicable accounting guidance, the fair value of the assets acquired and liabilities assumed was determined as of the acquisition date through the use of significant estimates and assumptions that are judgmental in nature. Some of the more significant estimates and assumptions used include: projected future cash flows (including the amount and timing); discount rates reflecting the risk inherent in the future cash flows; and future power and fuel market prices. Additionally, market prices based on the Market Price Referent (MPR) established by the CPUC for renewable energy resources were used in determining the fair value of the Antelope Valley assets acquired and liabilities assumed. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. Generation did not record any goodwill related to any of the respective acquisitions.

The following table summarizes the acquisition-date fair value of the consideration transferred and the assets and liabilities assumed for each of the companies acquired by Generation during the years ended December 31, 2011 and December 31, 2010:

	Acquisitions		
	2011		2010
	Wolf Hollow	Antelope Valley	Exelon Wind
Fair value of consideration transferred			
Cash	$305	$ 75	$893
Plus: Gain on PPA settlement	6	—	—
Contingent consideration	—	—	32
Total fair value of consideration transferred	$311	$ 75	$925
Recognized amounts of identifiable assets acquired and liabilities assumed			
Property, plant and equipment	$347	$ 15	$700
Inventory	5	—	—
Intangible assets (a)	—	190	224
Payable to First Solar, Inc. (b)	—	(135)	—
Working capital, net	(5)	—	18
Asset retirement obligations	—	—	(13)
Noncontrolling interest	—		(3)
Other Assets	—	5	(1)
Total net identifiable assets	$347	$ 75	$925
Bargain purchase gain	$ 36	$ —	$ —

(a) See Note 8—Intangible Assets for additional information.

(b) Generation concluded that the remaining, yet-to-be paid $135 million in consideration was embedded in the amounts payable under the Engineering, Procurement, Construction (EPC) agreement for First Solar, Inc. to construct the solar facility. For accounting purposes, this aspect of the transaction is considered to be akin to a "seller financing" arrangement. As such, Generation recorded a liability of $135 million associated with the portion of the future payments to First Solar, Inc. under the EPC agreement to reflect Generation's implicit amounts due First Solar, Inc. for the remainder of the value of the net assets acquired. The $135 million payable to First Solar, Inc. will be relieved as Generation makes payments for costs incurred over the project construction period. At December 31, 2012, $87 million remained payable to First Solar, Inc.

Wolf Hollow, LLC. 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. The acquisition supports the Exelon commitment to renewable energy as part of Exelon 2020.

Generation recognized an approximately $36 million non-cash bargain purchase gain (i.e., negative goodwill). The gain was included within Other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.

The pro forma impact of this acquisition would not have been material to Exelon's results of operations for the years ended December 31, 2011 and 2010.

Antelope Valley Solar Ranch One. On September 30, 2011, Generation acquired Antelope Valley Solar Ranch One (Antelope Valley), a 230-MW solar 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. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

Exelon expects to invest up to $701 million in equity in the project through 2013. The DOE's Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the project. On April 5, 2012, Antelope Valley received the first DOE-guaranteed loan advance of $69 million and terminated the put option that Generation had on the Antelope Valley project. See Note 11—Debt and Credit Agreements for additional information on the DOE loan guarantee.

The pro forma impact of this acquisition would not have been material to Exelon's results of operations for the years ended December 31, 2011 and 2010.

Exelon Wind. On December 9, 2010, Generation paid consideration of $893 million to complete the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power. Under the terms of the agreement, Generation added 735 MWs of installed, operating wind capacity located in eight states. The acquisition supports Exelon's commitment to renewable energy as part of Exelon 2020.

The contingent consideration arrangement requires that Generation pay up to $40 million related to three individual projects with an aggregate capacity of 230 MWs, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. The fair value of the contingent consideration arrangement of $32 million was determined as of the acquisition date based upon a weighted average probability of meeting certain contractual commitments related to the commencement of construction of each project, which is considered an unobservable (Level 3) input pursuant to applicable accounting guidance. During the third quarter of 2011, $16 million of contingent consideration was paid to Deere & Company for one of the projects and the probability of a second project beginning construction, Harvest II, was increased to 100%. As a result, the contingent consideration included in other current liabilities within Exelon's Consolidated Balance Sheets was adjusted to $10 million to reflect the full expected contingent payment related to the Harvest II project and subsequently paid to Deere & Company during the third quarter of 2012. Additionally, $2 million was recorded in operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income. The remaining $8 million of contingent consideration is included in other current liabilities within Exelon's Consolidated Balance Sheets.

The fair value of the assets acquired included customer receivables of $18 million. There are no outstanding customer receivables that were acquired in the Exelon Wind transaction.

The $3 million noncontrolling interest represents the noncontrolling members' proportionate share in the fair value of the assets acquired and liabilities assumed in the transaction.

The pro forma impact of this acquisition would not have been material to Exelon's results of operations for the year ended December 31, 2010.

5. Accounts Receivable

Accounts receivable at December 31, 2012 and 2011 included estimated unbilled revenues, representing an estimate for the unbilled amount of energy or services provided to customers, and is net of an allowance for uncollectible accounts as follows:

	2012	2011
Unbilled customer revenues	$1,418	$ 902
Allowance for uncollectible accounts [(a)]	(293)	(199)

(a) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(b) Includes an allowance for uncollectible accounts of $7 million and $8 million at December 31, 2012 and 2011, respectively, related to PECO's current installment plan receivables described below.

PECO Installment Plan Receivables. PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $18 million and $21 million as of December 31, 2012 and 2011, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1—Significant Accounting Policies. The allowance for uncollectible accounts balance associated with these receivables at December 31, 2012 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2011 of $17 million consists of $1 million, $3 million and $13 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of December 31, 2012 and 2011 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1—Significant Accounting Policies.

Accounts Receivable Agreement. PECO is party to an agreement with a financial institution under which it sold an undivided interest, adjusted daily, in up to $225 million of designated accounts receivable, which is accounted for as a secured borrowing. On November 28, 2012, PECO made a principal paydown of $15 million to meet the compliance requirements for the October 2012 reporting period. The remaining principal balance of $210 million is classified as a short-term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of December 31, 2012 and 2011, the financial institution's undivided interest in PECO's gross accounts receivable was equivalent to $289 million and $329 million, respectively, which is calculated under the terms of the agreement. See Note 11—Debt and Credit Agreements for additional information regarding the accounts receivable agreement.

6. Property, Plant and Equipment

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2012 and 2011:

	Average Service Life (years)	2012	2011
Asset Category			
Electric—transmission and distribution	5 - 90	$26,576	$21,716
Electric—generation [(a)]	1 - 53	19,004	13,682
Gas—transportation and distribution	5 - 90	3,108	1,793
Common—electric and gas	5 - 50	1,029	564
Nuclear fuel [(b)]	1 - 8	4,815	4,225
Construction work in progress	N/A	1,926	1,110
Other property, plant and equipment [(c)]	3 - 72	912	439
Total property, plant and equipment		57,370	43,529
Less: accumulated depreciation [(d)]		12,184	10,959
Property, plant and equipment, net		$45,186	$32,570

(a) Includes assets acquired through acquisitions. See Note 4—Mergers and Acquisitions for additional information.
(b) Includes nuclear fuel that is in the fabrication and installation phase of $894 million and $674 million at December 31, 2012 and 2011, respectively.
(c) Includes Generation's buildings under capital lease with a net carrying value of $20 million and $23 million at December 31, 2012 and 2011, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $33 million and $30 million as of December 31, 2012 and 2011, respectively. Also includes land held for future use and non utility property at ComEd, PECO and BGE. These balances also include capitalized acquisition, development and exploration costs related to oil and gas production activities at Generation.
(d) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $2,078 million and $1,784 million as of December 31, 2012 and 2011, respectively.

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2012	2011	2010
Electric—transmission and distribution	2.76%	2.59%	2.53%
Electric—generation	3.15%	3.12%	2.86%
Gas	2.03%	1.73%	1.75%
Common—electric and gas	7.61%	8.05%	7.25%

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.15%, 3.12% and 2.86% for the years ended December 31, 2012, 2011 and 2010, respectively.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.79%, 2.67% and 2.64% for the years ended December 31, 2012, 2011 and 2010, respectively.

License Renewals. Generation's depreciation provisions are based on the estimated useful lives of its generating stations, which assume the renewal of the licenses for all nuclear generating stations (except for Oyster Creek) and the hydroelectric generating stations. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 3—Regulatory Matters for additional information regarding license renewals.

See Note 1—Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon. See Note 11—Debt and Credit Agreements for further information regarding Exelon's property, plant and equipment subject to mortgage liens.

7. Jointly Owned Electric Utility Plant

Exelon, Generation, PECO and BGE's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2012 and 2011 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem (a)	Keystone (b)	Conemaugh (b)	Wyman	PA (c)	DE/NJ (d)	Other (e)
Operator	Generation	Generation	PSEG Nuclear	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	41.98%	31.28%	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2012:									
Plant (f)	$ 874	$ 796	$ 494	$ 624	$ 322	$ 3	$ 13	$ 65	$ 1
Accumulated depreciation (f)	187	302	119	153	158	3	7	33	—
Construction work in progress	44	115	11	10	57	—	1	—	—
Exelon's share at December 31, 2011:									
Plant (f)	$ 822	$ 650	$ 420	$ 366	$ 271	$ 3	$ 5	$ 66	$ 1
Accumulated depreciation (f)	156	285	103	137	154	3	3	33	—
Construction work in progress	37	111	61	5	15	—	—	—	—

(a) Generation also owns a proportionate share in the fossil fuel combustion turbine at Salem, which is fully depreciated. The gross book value was $3 million at December 31, 2012 and 2011.
(b) Generation's ownership interest in Keystone and Conemaugh has increased as a result of Exelon's merger with Constellation in 2012. See Note 4 for additional information.
(c) PECO and BGE own a 22% and 7% share, respectively, in 127 miles of 500 kV lines located in Pennsylvania; PECO and BGE also own a 20.7% and 10.56% share, respectively, of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines including, but not limited to, the lines noted above.
(d) PECO owns a 42.55% share in 131 miles of 500 kV lines located in Delaware and New Jersey as well as a 42.55% share in a 500kV substation immediately outside of the Salem nuclear generating station in New Jersey which supplies power to the 500kV lines including, but not limited to, the lines noted above.
(e) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.
(f) Excludes asset retirement costs.

Exelon's, Generation's, PECO's and BGE's undivided ownership interests are financed with their funds and all operations are accounted for as if such participating interests were wholly owned facilities. Exelon's, Generation's, PECO's and BGE's share of direct expenses of the jointly owned plants are included in fuel and operating and maintenance expenses on Exelon's and Generation's Consolidated Statements of Operations and in operating and maintenance expenses on PECO's and BGE's Consolidated Statements of Operations.

8. Intangible Assets

Goodwill

Exelon's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2012 and 2011 was as follows:

	2012 and 2011		
	Gross Amount (a)	Accumulated Impairment Losses	Carrying Amount
Balance, January 1,	$4,608	$1,983	$2,625
Impairment losses	—	—	—
Balance, December 31,	$4,608	$1,983	$2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom (predecessor parent company of ComEd) merger net of amortization, resolution of tax matters and other non-impairment-related changes as allowed under previous authoritative guidance.

Goodwill is not amortized, but is subject to an assessment for impairment at least annually, or more frequently if events or circumstances indicate that goodwill is more likely than not impaired, such as a significant negative regulatory outcome, that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount.

In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised guidance, which became effective January 1, 2012, entities assessing goodwill for impairment have the option of performing a qualitative assessment before calculating the fair value of the reporting unit (i.e., step one of the two-step fair value based impairment test). If an entity determines, on the basis of qualitative factors, that the fair value of the reporting unit is more likely than not less than the carrying amount, the two-step fair value based impairment test is required. Otherwise, no further testing is required.

If an entity bypasses the qualitative assessment or performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount, a two-step, fair value based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Exelon assesses goodwill impairment at its ComEd reporting unit. Accordingly, any goodwill impairment charge at ComEd will affect Exelon's consolidated results of operations. Under the effective authoritative guidance for fair value measurement, Exelon and ComEd estimate the fair value of the ComEd reporting unit using a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case" or "best estimate" projected cash flows for ComEd's business and includes an estimate of ComEd's terminal value based on these expected cash flows using the generally accepted Gordon Dividend Growth formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is based on the generally accepted Capital Asset Pricing Model and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to earnings, before interest, taxes, depreciation and amortization (EBITDA) of comparable companies in estimating fair value. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd's business and the fair value of debt. Management performs a reconciliation of the sum of the estimated fair value of all Exelon reporting units to Exelon's enterprise value based on its trading price to corroborate the results of the discounted cash flow analysis and the market multiple analysis.

2012 Interim Goodwill Impairment Assessment. In May 2012, the ICC issued a final Order (Order) in ComEd's 2011 formula rate proceeding under EIMA that reduced ComEd's annual revenue requirement being recovered in current rates by $168 million. Management concluded that the Order represented an event that required an interim goodwill impairment assessment and as a result, ComEd tested its goodwill for impairment as of May 31, 2012. The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Consistent with prior annual impairment tests, the estimated fair value of ComEd was determined using a weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting "base case" or management's best estimate of projected cash flows for ComEd's business. In performing the discounted cash flow analysis for the interim goodwill test, management assumed that ComEd would ultimately prevail in appealing certain aspects of the May Order, specifically the return on ComEd's pension asset and the use of year-end rate base in determining ComEd's annual revenue requirement being recovered in current rates. The disallowances related to the pension asset return and year-end rate base were estimated to reduce ComEd's revenue requirement recovered in rates by approximately $75—$130 million annually. The assessment also reflected several favorable changes in certain market assumptions since the annual impairment assessment in 2011, including the weighted average cost of capital and market multiples.

Based on the results of the interim goodwill test, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

On October 3, 2012, the ICC issued its Rehearing Order in response to ComEd's expedited rehearing request. The Rehearing Order adopted ComEd's position on the return on its pension asset resulting in an increase in ComEd's annual revenue. See Note 3—Regulatory Matters for further detail.

2012 Annual Goodwill Impairment Assessment. ComEd performed a qualitative assessment as of November 1, 2012, for its 2012 annual goodwill impairment assessment and while certain factors indicated a reduction in fair value since May 31, 2012, ComEd determined that its fair value was not more likely than not less than its carrying value. Therefore, ComEd did not perform a quantitative assessment. As part of its qualitative assessment, ComEd evaluated, among other things, management's best estimate of projected operating and capital cash flows for ComEd's business (including the impacts of the Rehearing Order) as well as changes in certain other market conditions such as the discount rate and EBITDA multiples.

While neither the interim nor the annual assessments indicated an impairment of ComEd's goodwill, a change in management's assumption regarding the outcome of the IRS' challenge of Exelon's and ComEd's like-kind exchange income tax position, adverse regulatory actions such as early termination of EIMA, or changes in the significant assumptions described above could potentially result in a future impairment of ComEd's goodwill, which could be material. ComEd will assess whether its goodwill has been impaired in the first quarter of 2013 in connection with the reassessment of the like-kind exchange position and the associated charge to ComEd's earnings. See Note 12 for additional information.

Prior Goodwill Impairment Assessments. The 2011 and 2010 annual goodwill impairment assessments were performed as of November 1, 2011 and November 1, 2010, respectively. In each case, the first step of the annual impairment analysis, comparing the fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. ComEd will assess whether its goodwill has been impaired in the first quarter of 2013 in connection with the reassessment of the like-kind exchange position and the charge to ComEd's earnings. See Note 12 for additional information.

Other Intangible Assets

For discussion surrounding Exelon's unamortized energy contracts, trade name and retail relationships recorded in conjunction with the Merger refer to Note 4—Merger and Acquisitions.

Exelon's other intangible assets, included in unamortized energy contract assets and deferred debits and other assets in its Consolidated Balance Sheets, consisted of the following as of December 31, 2012:

				Estimated amortization expense				
	Gross	Accumulated Amortization	Net	2013	2014	2015	2016	2017
Exelon Wind acquisition [(a)]	$224	$ (26)	$198	$14	$14	$14	$14	$14
Antelope Valley acquisition [(b)]	190	—	190	7	8	8	8	8
Chicago settlement–1999 agreement [(c)]	100	(72)	28	3	3	3	3	4
Chicago settlement–2003 agreement [(d)]	62	(34)	28	4	4	4	4	3
Total intangible assets	$576	$(132)	$444	$28	$29	$29	$29	$29

(a) Refer to Note 4—Merger and Acquisitions for additional information regarding Exelon Wind.
(b) Refer to Note 4—Merger and Acquisitions for additional information regarding Antelope Valley.
(c) In March 1999, ComEd entered into a settlement agreement with the City of Chicago associated with ComEd's franchise agreement. Under the terms of the settlement, ComEd agreed to make payments to the City of Chicago each year from 1999 to 2002. The intangible asset recognized as a result of these payments is being amortized ratably over the remaining term of the franchise agreement, which ends in 2020.
(d) In February 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation, LLC (Midwest Generation). Under the terms of the settlement agreement with the City of Chicago, ComEd agreed to pay the City of Chicago a total of $60 million over a ten-year period, beginning in 2003. The intangible asset recognized as a result of the settlement agreement is being amortized ratably over the remaining term of the City of Chicago franchise agreement, which ends in 2020. As required by the settlement, ComEd also made a payment of $2 million to a third party on the City of Chicago's behalf. Under the terms of the agreement with Midwest Generation, ComEd received payments of $32 million from Midwest Generation to relieve Midwest Generation's obligation under the 1999 fossil sale agreement with ComEd to build the generation facility in the City of Chicago. The payments received by ComEd, which have been recorded in other long-term liabilities, are being recognized ratably (approximately $2 million annually) as an offset to amortization expense over the remaining term of the franchise agreement.

The following table summarizes the amortization expense related to intangible assets for each of the years ended December 31, 2012, 2011 and 2010:

	For the year Ended December 31,
2012	$20
2011	19
2010	8

Acquired Intangible Assets

Accounting guidance for business combinations requires that the acquirer must recognize separately identifiable intangible assets in the application of purchase accounting. The valuation of the acquired intangible assets discussed below were estimated by applying the income approach, which is based upon discounted projected future cash flows associated with the respective PPAs. Those measures are based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance.

Exelon Wind. The output of the acquired wind turbines has been sold under PPA contracts. The excess of the contract price of the PPAs over market prices was recognized as intangible assets at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible assets was approximately $224 million, which is recorded in unamortized energy contract assets within Exelon's Consolidated Balance Sheets.

Key assumptions used in the valuation of the intangible assets include forecasted power prices and discount rate. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The intangible assets are amortized on a straight-line basis over the period in which the associated contract revenues are recognized. The amortization expense is reflected as a decrease in operating revenue within Exelon's Consolidated Statements of Operations and Comprehensive Income. The weighted-average amortization period for these intangibles is approximately 18 years.

Antelope Valley. Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric Company. The excess of the contract price of the PPA over forecasted MPR-based market prices was recognized as an intangible asset at the acquisition date. Generation determined that the estimated acquisition-date fair value of the intangible asset was approximately $190 million, which is recorded in unamortized energy contract assets within Exelon's Consolidated Balance Sheets. While Generation expects to perform under the PPA once the construction of this project is complete, there is a risk of impairment if the project does not reach commercial operation.

Key assumptions used in the valuation of the intangible asset include forecasted MPR-based market prices and discount rate. The measure is based upon certain unobservable inputs, which are considered Level 3 inputs, pursuant to applicable accounting guidance. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the acquisition date. The intangible asset will be amortized as a decrease in operating revenue within Exelon's Consolidated Statements of Operations and Comprehensive Income over the 25 year term of the underlying PPA.

Renewable Energy Credits and Alternative Energy Credits

Exelon's, Generation's, ComEd's and PECO's other intangible assets, included in other current assets and other deferred debits and other assets on the Consolidated Balance Sheets, include RECs and AECs. Revenue for RECs that are part of a bundled power sale is recognized when the power is produced and delivered to the customer. As of December 31, 2012, and 2011, PECO had current AECs of $17 million and $14 million, respectively, and noncurrent AECs of $9 million and $16 million, respectively. As of December 31, 2012, and 2011, Generation had current RECs of $61 million and $0 million, respectively, and noncurrent RECs of $45 million and $6 million, respectively. As of December 31, 2012, and 2011, ComEd, had current RECs of $18 million and $9 million, respectively, and noncurrent RECs of $49 million and $97, respectively. See Notes 1—Significant Accounting Policies, 3—Regulatory Matters and Note 19—Commitments and Contingencies for additional information on RECs and AECs.

9. Fair Value of Financial Assets and Liabilities

Fair Value of Financial Liabilities Recorded at the Carrying Amount

The following table presents the carrying amounts and fair values of Exelon's short-term liabilities, long-term debt, SNF obligation, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of December 31, 2012, and 2011:

	December 31, 2012				December 31, 2011	
		Fair Value				
	Carrying Amount	Level 1	Level 2	Level 3	Carrying Amount	Fair Value
Short-term liabilities	$ 214	$ 4	$ 210	$—	$ 737	$ 737
Long-term debt (including amounts due within one year)	18,745	—	20,244	276	12,627	14,488
Long-term debt to financing trusts	648	—	—	664	390	358
SNF obligation	1,020	—	763	—	1,019	886
Preferred securities of subsidiary	87	—	82	—	87	79

Short-Term Liabilities. The short-term liabilities included in the table above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO's accounts receivable agreement (Level 2), and dividends payable (Level 1). Exelon's carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 11—Debt and Credit Agreements for additional information on PECO's accounts receivable agreement.

Long-Term Debt. The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

Generation has fixed rate project financing debt (Level 3), the fair value of which is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, for certain government-backed debt, discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value.

Exelon also has tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

SNF Obligation. The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

Long-Term Debt to Financing Trusts. Due to low trading volume of similar securities (Level 3), qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, may be incorporated into the credit spreads that are used to obtain the fair value as described above.

Preferred Securities. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the SEC and are public.

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1—quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities, certain exchange-based derivatives, and money market funds.
- Level 2—inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, non-exchange-based derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.
- Level 3—unobservable inputs, such as internally developed pricing models or third party valuations for the asset or liability due to little or no market activity for the asset or liability. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded non-exchange-based derivatives, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

There were no transfers between Level 1 and Level 2 during the year ended December 31, 2012.

The following tables present assets and liabilities measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2012 and December 31, 2011:

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 995	$ —	$—	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245	—	—	245
Equity				
Equity securities	1,480	—	—	1,480
Commingled funds	—	1,933	—	1,933
Equity funds subtotal	1,480	1,933	—	3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057	—	—	1,057
Debt securities issued by states of the United States and political subdivisions of the states	—	321	—	321
Debt securities issued by foreign governments	—	93	—	93
Corporate debt securities	—	1,788	—	1,788
Federal agency mortgage-backed securities	—	24	—	24
Commercial mortgage-backed securities (non-agency)	—	45	—	45
Residential mortgage-backed securities (non-agency)	—	11	—	11
Mutual funds	—	23	—	23
Fixed income subtotal	1,057	2,305	—	3,362
Middle market lending	—	—	183	183
Other debt obligations	—	15	—	15
Nuclear decommissioning trust fund investments subtotal [(b)]	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents	—	23	—	23
Equity				
Equity securities	14	—	—	14
Commingled funds	—	9	—	9
Equity funds subtotal	14	9	—	23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12	—	130
Debt securities issued by states of the United States and political subdivisions of the states	—	37	—	37
Corporate debt securities	—	249	—	249
Federal agency mortgage-backed securities	—	49	—	49
Commercial mortgage-backed securities (non-agency)	—	6	—	6
Fixed income subtotal	118	353	—	471
Middle market lending	—	—	89	89
Other debt obligations	—	1	—	1

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Pledged assets for Zion decommissioning subtotal [c]	132	386	89	607
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [d]	69	—	—	69
Rabbi trust investments subtotal	71	—	—	71
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral [f]	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal [g]	80	1,076	656	1,812
Interest rate mark-to-market derivative assets	—	114	—	114
Effect of netting and allocation of collateral	—	(51)	—	(51)
Interest rate mark-to-market derivative assets subtotal	—	63	—	63
Other Investments	2	—	17	19
Total assets	4,062	5,778	945	10,785
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral [f]	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal [g][h]	(83)	(228)	(289)	(600)
Interest rate mark-to-market derivative liabilities	—	(84)	—	(84)
Effect of netting and allocation of collateral	—	51	—	51
Interest rate mark-to-market derivative liabilities subtotal	—	(33)	—	(33)
Deferred compensation	—	(102)	—	(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$10,050

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 861	$ —	$—	$ 861
Nuclear decommissioning trust fund investments				
Cash equivalents	562	—	—	562
Equity				
Equity securities	1,275	—	—	1,275
Commingled funds	—	1,822	—	1,822
Equity funds subtotal	1,275	1,822	—	3,097
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,014	33	—	1,047
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Debt securities issued by foreign governments	—	16	—	16
Corporate debt securities	—	778	—	778
Federal agency mortgage-backed securities	—	357	—	357
Commercial mortgage-backed securities (non-agency)	—	83	—	83
Residential mortgage-backed securities (non-agency)	—	5	—	5
Mutual funds	—	47	—	47
Fixed income subtotal	1,014	1,860	—	2,874
Middle market lending	—	—	13	13
Other debt obligations	—	18	—	18
Nuclear decommissioning trust fund investments subtotal [(b)]	2,851	3,700	13	6,564
Pledged assets for Zion decommissioning Equity				
Equity securities	35	—	—	35
Commingled funds	—	30	—	30
Equity funds subtotal	35	30	—	65
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	54	26	—	80
Debt securities issued by states of the United States and political subdivisions of the states	—	65	—	65
Corporate debt securities	—	314	—	314
Federal agency mortgage-backed securities	—	121	—	121
Commercial mortgage-backed securities (non-agency)	—	10	—	10
Commingled funds	—	20	—	20
Fixed income subtotal	54	556	—	610
Middle market lending	—	—	37	37
Other debt obligations	—	13	—	13
Pledged assets for Zion decommissioning subtotal [(c)]	89	599	37	725
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds [(d)(e)]	34	—	—	34

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Rabbi trust investments subtotal	36	—	—	36
Commodity mark-to-market derivative assets				
Cash flow hedges	—	857	—	857
Economic hedges	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Effect of netting and allocation of collateral [f]	—	(1,827)	(28)	(1,855)
Commodity mark-to-market assets [g]	—	923	144	1,067
Interest rate mark-to-market derivative assets	—	15	—	15
Total assets	3,837	5,237	194	9,268
Liabilities				
Commodity mark-to-market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Economic hedges	(1)	(1,137)	(119)	(1,257)
Proprietary trading	—	(236)	(28)	(264)
Effect of netting and allocation of collateral [f]	—	1,295	20	1,315
Commodity mark-to-market liabilities [h]	(1)	(91)	(127)	(219)
Interest rate mark-to-market liabilities	—	(19)	—	(19)
Deferred compensation	—	(73)	—	(73)
Total liabilities	(1)	(183)	(127)	(311)
Total net assets	$3,836	$ 5,054	$ 67	$ 8,957

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net assets (liabilities) of $30 million and $(57) million at December 31, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(c) Excludes net assets of $7 million and $9 million at December 31, 2012 and December 31, 2011, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) The mutual funds held by the Rabbi trusts include $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan. These funds are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

(e) Excludes $28 million and $25 million of the cash surrender value of life insurance investments at December 31, 2012 and December 31, 2011, respectively.

(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $532 million and $8 million allocated to Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2011.

(g) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million and $0 million at December 31, 2012 and $503 million and $191 million at December 31, 2011, respectively, related to the fair value of Generation's financial swap contract with ComEd.

(h) The Level 3 balance includes the current and noncurrent liability of $18 million and $49 million at December 31, 2012, respectively, and $9 million and $97 million at December 31, 2011, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2012 and 2011:

For the Year Ended December 31, 2012	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives [(b)]	Other Investments	Total
Balance as of January 1, 2012	$ 13	$ 37	$ 17	$—	$ 67
Total realized / unrealized gains (losses)					
Included in net income	—	—	(119) [(a)]	—	(119)
Included in other comprehensive income	—	—	—	—	—
Included in regulatory assets	1	—	39	—	40
Included in payable for Zion Station decommissioning	—	—	—	—	—
Change in collateral	—	—	(32)	—	(32)
Purchases, sales, issuances and settlements					
Purchases	169	63	334 [(c)]	17	583
Sales	—	(11)	—	—	(11)
Transfers into Level 3	—	—	39	—	39
Transfers out of Level 3	—	—	89	—	89
Balance as of December 31, 2012	$183	$ 89	$ 367	$ 17	$ 656
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held as of December 31, 2012	$—	$—	$ 37	$—	$ 37

(a) Includes the reclassification of $156 million of realized losses due to settlement of derivative contracts recorded in results of operations for the year ended December 31, 2012.

(b) Excludes $98 million of increases in fair value and $566 million of realized losses due to settlements for the year ended December 31, 2012 of Generation's financial swap contract with ComEd, which eliminates upon consolidation in Exelon's Consolidated Financial Statements. This position was de-designated as a cash flow hedge prior to the merger date. All prospective changes in fair value and reclassifications of realized amounts are being recorded to income offset by the amortization of the frozen mark in OCI.

(c) Includes $323 million of fair value from contracts and $17 million of other investments acquired as a result of the merger.

For the Year Ended December 31, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Decommissioning	Mark-to-Market Derivatives	Total
Balance as of January 1, 2011	$—	$—	$ 50	$ 50
Total realized / unrealized gains (losses)				
Included in income	1	—	99	100
Included in other comprehensive income	—	—	(25)[(a)]	(25)
Included in regulatory liabilities	2	—	(106)[(b)]	(104)
Change in collateral	—	—	6	6
Purchases, sales, issuances and settlements				
Purchases	10	60	10	80
Sales	—	(23)	—	(23)
Transfers out of Level 3	—	—	(17)	(17)
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$ 67
The amount of total gains included in income attributed to the change in unrealized gains (losses) related to assets and liabilities as of December 31, 2011	$ 1	$—	$ 131	$ 132

(a) Includes the reclassification of $32 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the year ended December 31, 2011.

(b) Excludes $170 million of increases in fair value and $451 million of realized losses due to settlements associated with Generation's financial swap contract with ComEd and $5 million of changes in the fair value of Generation's block contracts with PECO for the year ended December 31, 2011. All items eliminate upon consolidation if Exelon's Consolidated Financial Statements.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the years ended December 31, 2012 and 2011:

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the year ended December 31, 2012	$(153)	$34
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2012	$ 13	$24

	Operating Revenue	Purchased Power and Fuel
Total gains (losses) included in income for the year ended December 31, 2011	$ 108	$ (8)
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2011	$ 137	$ (5)

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents. Exelon's cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning. The trust fund investments have been established to satisfy Generation's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation's investment policies place limitations on the types and investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds' exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which

Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable on the 15th of the month and the last business day of the month; however, the fund manager may designate any day as a valuation date for the purpose of purchasing or redeeming units. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Rabbi Trust Investments. The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon's executive management and directors. The investments in the Rabbi trusts are included in investments in Exelon's Consolidated Balance Sheets. The investments are in fixed-income commingled funds and mutual funds, including short-term investment funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For fixed-income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the NAV per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Fixed-income commingled funds and mutual funds which are publicly quoted, such as money market funds, have been categorized as Level 1 given the clear observability of the prices.

Mark-to-Market Derivatives. Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain non-exchange-based derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid-ask, mid-point prices and are obtained from sources that Exelon believes provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid-ask spreads and contract duration. The remainder of non-exchange-based derivative contracts is valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For non-exchange-based derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. Exelon's non-exchange-based derivatives are predominately at liquid trading points. For non-exchange-based derivatives that trade in less liquid markets with limited pricing information, such as the financial swap contract between Generation and ComEd, model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, Exelon may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market's expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10—Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations. Exelon's deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. Exelon includes such plans in other current and noncurrent liabilities in its Consolidated Balance Sheets. The value of Exelon's deferred compensation obligations is based on the market value of the participants' notional investment accounts. The notional investments are comprised primarily of mutual funds, which are based on observable market prices. However, since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized in Level 2 in the fair value hierarchy.

Additional Information Regarding Level 3 Fair Value Measurements

Mark-to-Market Derivatives. For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements. Transfers in and out of levels are recognized as of the end of the reporting period the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 generally do not occur. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts.

Disclosed below is detail surrounding Exelon's significant Level 3 valuations. The most significant position is the long term intercompany swap with ComEd, which is further discussed in Note 10—Derivative Financial Instruments. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation's remaining Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties, and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instruments market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is generally less than $4 and $.25 for power and natural gas respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See Quantitative and Qualitative Disclosures About Market Risk for information regarding the maturity by year of Exelon's mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 10—Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at December 31, 2012 (d)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives—Economic Hedges (Generation) (a)	$473	Discounted Cash Flow	Forward power price	$14 - $79
			Forward gas price	$3.26 - $6.27
		Option Model	Volatility percentage	28% - 132%
Mark-to-market derivatives—Proprietary trading (Generation) (a)	$ (6)	Discounted Cash Flow	Forward power price	$15 - $106
		Option Model	Volatility percentage	16% - 48%
Mark-to-market derivatives—Transactions with affiliates (Generation and ComEd) (b)	$226	Discounted Cash Flow	Marketability reserve	8% - 9%
Mark-to-market derivatives (ComEd)	$ (67)	Discounted Cash Flow	Forward heat rate (c)	8% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	81% - 123%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $226 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.
d) The fair values do not include cash collateral held on Level 3 positions of $33 million as of December 31, 2012.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give us the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give us the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning. For middle market lending the fair value of these loans is determined using a combination of valuations models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the applications of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability and relative performance.

Because Generation relies on third party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its' middle market lending, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its' middle market lending, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

10. Derivative Financial Instruments

Exelon is exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

Commodity Price Risk

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, Exelon is exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Exelon employs established policies and procedures to manage its risks associated with market fluctuations by entering into physical contracts as well as financial derivative contracts including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. Exelon believes these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation will no longer utilize the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation's designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. Exelon has applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 19—Commitments and Contingencies. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

Economic Hedging. Exelon is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels, and other commodities associated with price movements resulting from changes in supply and demand, fuel costs, market liquidity, weather conditions, governmental regulatory and environmental policies, and other factors. Within Exelon, Generation has the most exposure to commodity price risk. Generation uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. 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. 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.

ComEd has locked in a fixed price for a significant portion of its commodity price risk through the five-year financial swap contract with Generation that expires on May 31, 2013, which is discussed in more detail below. In addition, the contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3—Regulatory Matters, qualify for the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd's price risk related to power procurement is limited.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract effective August 28, 2007. The financial swap is designed to hedge spot market purchases, which, along with ComEd's remaining energy procurement contracts, meet its load service requirements. The remaining swap contract volume is 3,000 MWs through May 2013. The terms of the financial swap contract require Generation to pay the around-the-clock market price for a portion of ComEd's electricity supply requirement, while ComEd pays a fixed price. The contract is to be settled net, for the difference between the fixed and market pricing, and the financial terms only cover energy costs and do not cover capacity or ancillary services. The financial swap contract is a derivative financial instrument that was originally designated by Generation as a cash flow hedge. As discussed previously, effective with the date of merger with Constellation, Generation de-designated this swap as a cash flow hedge and began recording changes in fair value through current earnings as of that date. Generation records the fair value of the swap on its balance sheet and originally recorded changes in fair value to OCI. The value frozen in OCI as of the date of merger for this swap is reclassified into Generation's earnings as the swap settles. ComEd has not elected hedge accounting for this derivative financial instrument. Since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates and, therefore, the change in fair value each period is recorded as a regulatory asset or liability on ComEd's Consolidated Balance Sheets. See Note 3—Regulatory Matters for additional information regarding the Illinois Settlement Legislation. In Exelon's consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 3—Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO's full requirements contracts and block contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance. For block contracts designated as normal purchases after inception, the mark-to-market balances previously recorded on PECO's Consolidated Balance Sheet were amortized over the terms of the contracts, which ended on December 31, 2011.

PECO's natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO's reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO's natural gas supply and asset management agreements that are derivatives either qualify for the normal purchases and normal sales scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2012 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2012 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its Standard Offer Service requirements through full requirements contracts. BGE's full requirements contracts, which are considered derivatives, qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the market-based rates incentive mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the normal purchases and normal sales exception and result in physical delivery.

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 12,958 GWh, 5,742 GWh and 3,625 Gwh for the years ended December 31, 2012, 2011 and 2010, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

Interest Rate Risk

Exelon uses a combination of fixed-rate and variable-rate debt to manage interest rate exposure. Exelon may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, Exelon may utilize interest rate derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At December 31, 2012, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $452 million of notional amounts of pre-issuance hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $2 million decrease in Exelon Consolidated pre-tax income for the year ended December 31, 2012. Below is a summary of the interest rate hedges as of December 31, 2012.

	Generation					Other	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading (a)**	**Collateral and Netting (b)**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (Current Assets)	$—	$ 3	$ 20	$(19)	$ 4	$—	$ 4
Mark-to-market derivative assets (Noncurrent Assets)	38	$ 8	$ 32	(32)	46	13	59
Total mark-to-market derivative assets	$ 38	$ 11	$ 52	$(51)	$ 50	$ 13	$ 63
Mark-to-market derivative liabilities (Current Liabilities)	$ (1)	$ (1)	$(19)	$ 19	$ (2)	$—	$ (2)
Mark-to-market derivative liabilities (Noncurrent Liabilities)	(31)	$—	$(32)	32	(31)	—	(31)
Total mark-to-market derivative liabilities	$(32)	$ (1)	$(51)	$ 51	$(33)	$—	$(33)
Total mark-to-market derivative net assets (liabilities)	$ 6	$ 10	$ 1	$—	$ 17	$ 13	$ 30

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts between the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Represents the netting of fair value balances with the same counterparty and collateral.

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

	Gain (Loss) on Swaps			Gain (Loss) on Borrowings		
	Twelve Months Ended December 31,			Twelve Months Ended December 31,		
Income Statement Classification	**2012**	**2011**	**2010**	**2012**	**2011**	**2010**
Interest expense (a)	$(6)	$1	$4	$(6)	$(1)	$(4)

(a) For the year ended December 31, 2012, the loss on the swaps in the table above includes $12 million reclassified to earnings, with an immaterial amount excluded from hedge effectiveness testing.

At December 31, 2012, and December 31, 2011, Exelon had $650 million and $100 million, respectively, of notional amounts of fixed-to-floating fair value hedges outstanding related to interest rate swaps, with unrealized gain of $49 million and $15 million, respectively, which expire in 2015. Upon merger closing, $550 million of fixed-to-floating interest rate swaps previously at Constellation with a fair value of $44 million, as of March 12, 2012, were re-designated as fair value hedges. During the years ended December 31, 2012, and December 31, 2011, the impact on the results of operations as a result of ineffectiveness from fair value hedges was immaterial.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 11—Debt and Credit Agreements, Generation entered into a floating-to-fixed forward starting interest rate swap with a notional amount of $485 million and a mandatory early termination date of April 5, 2014, by which date Generation anticipates the DOE loan to be fully drawn. The swap hedges approximately 75% of Generation's future interest rate exposure associated with the financing and was designated as a cash flow hedge. As such, the effective portion of the hedge will be recorded in other comprehensive income within Generation's Consolidated Balance Sheets in Exelon's 2012 Form 10-K, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income in Exelon's 2012 Form 10-K. Net gains (or losses) from settlement of the hedges, to the extent effective, will be amortized as an adjustment to the interest expense over the term of the DOE guaranteed loan.

As Generation draws down on the loan, a portion of the cash flow hedge will be de-designated and the related gains or losses going forward will be reflected in earnings. In order to mitigate this earnings impact, a series of offsetting hedge transactions are executed as Generation draws on the loan.

Antelope Valley received its first loan advance on April 5, 2012, and several additional advances subsequently, as described in Note 11—Debt and Credit Agreements. Generation has entered into a series of fixed-to-floating interest rate swaps with an aggregated notional amount of $165 million, 75% of the loan advance amount to offset portions of the original interest rate hedge, which are de-designated as cash flow hedges. The remaining cash flow hedge has a notional amount of $320 million. At December 31, 2012, Generation's mark-to-market non-current derivative liability relating to the interest rate swap in connection with the loan agreement to fund Antelope Valley was $28 million.

During the third quarter of 2011, a subsidiary of Constellation entered into floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Sacramento PV Energy. The swaps have a total notional amount of $29 million as of December 31, 2012 and expire in 2027. After the closing of the merger with Constellation, the swaps were re-designated as cash flow hedges. At December 31, 2012, the subsidiary had a $4 million non-current derivative liability related to these swaps.

During the third quarter of 2012, a subsidiary of Exelon Generation entered into a floating-to-fixed forward starting interest rate swap to manage a portion of the interest rate exposure for anticipated long-term borrowings to finance Constellation Solar Horizons. The swap has a notional amount of $29 million as of December 31, 2012 and expires in 2030. This swap is designated as a cash flow hedge. At December 31, 2012, the subsidiary had an immaterial non-current derivative liability related to the swap.

During the third quarter of 2012, Exelon entered into $75 million floating-to-fixed forward starting interest rate hedges to manage interest rate risks associated with anticipated future debt issuance. These swaps are designated as cash flow hedges. At December 31, 2012, there is $1 million non-current derivative asset related to these swaps.

During the years ended December 31, 2012, and 2011, the impact on the results of operations as a result of ineffectiveness from cash flow hedges was immaterial.

Economic Hedges. At December 31, 2012, Exelon had $150 million of notional amounts of fixed-to-floating interest rate swaps that are marked-to-market, with an unrealized gain of $5 million. These swaps, which were acquired as part of the merger with Constellation, expire in 2014. During the period from March 12 to December 31, 2012, the impact on the results of operations was immaterial.

Fair Value Measurement

Fair value accounting guidance requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. In the table below, Generation's energy related cash flow hedges, economic hedges, and proprietary trading derivatives are shown gross and the impact of the netting of fair value balances with the same counterparty, as well as netting of collateral, is aggregated in the collateral and netting column. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2012:

	Generation				ComEd		Exelon
Derivatives	**Economic Hedges (a)**	**Proprietary Trading**	**Collateral and Netting (b)**	**Subtotal (c)**	**Economic Hedges (a)(d)**	**Intercompany Eliminations (a)**	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 2,883	$ 2,469	$(4,418)	$ 934	$ —	$ —	$ 934
Mark-to-market derivative assets with affiliate (current assets)	226	—	—	226	—	(226)	—
Mark-to-market derivative assets (noncurrent assets)	1,792	724	(1,638)	878	—	—	878
Total mark-to-market derivative assets	$ 4,901	$ 3,193	$(6,056)	$2,038	$ —	$(226)	$1,812
Mark-to-market derivative liabilities (current liabilities)	$(2,419)	$(2,432)	$ 4,519	$ (332)	$ (18)	$ —	$ (350)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	(226)	226	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,080)	(689)	1,568	(201)	(49)	—	(250)
Total mark-to-market derivative liabilities	$(3,499)	$(3,121)	$ 6,087	$ (533)	$(293)	$ 226	$ (600)
Total mark-to-market derivative net assets (liabilities)	$ 1,402	$ 72	$ 31	$1,505	$(293)	$ —	$1,212

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $226 million related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $28 million non current liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.

(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.

(c) Current and noncurrent assets are shown net of collateral of $113 million and $201 million, respectively, and current and noncurrent liabilities are shown net of collateral of $(214) million and $(131) million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $31 million at December 31, 2012.

(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2011:

	Generation					ComEd	Other		Exelon
Derivatives	**Cash Flow Hedges** (a)	**Economic Hedges**	**Proprietary Trading**	**Collateral and Netting** (b)	**Subtotal** (c)	**Economic Hedges** (a)(d)	**Economic Hedges**	**Intercompany Eliminations** (a)	**Total Derivatives**
Mark-to-market derivative assets (current assets)	$ 438	$ 1,195	$ 217	$(1,418)	$ 432	$ —	$—	$ —	$ 432
Mark-to-market derivative assets with affiliate (current assets)	503	—	—	—	503	—	—	(503)	—
Mark-to-market derivative assets (noncurrent assets)	419	582	71	(437)	635	—	15	—	650
Mark-to-market derivative assets with affiliate (noncurrent assets)	191	—	—	—	191	—	—	(191)	—
Total mark-to-market derivative assets	$1,551	$ 1,777	$ 288	$(1,855)	$1,761	$ —	$ 15	$(694)	$1,082
Mark-to-market derivative liabilities (current liabilities)	$ (9)	$ (965)	$(194)	$ 1,065	$ (103)	$ (9)	$—	$ —	$ (112)
Mark-to-market derivative liability with affiliate (current liabilities)	—	—	—	—	—	(503)	—	503	—
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)	(186)	(70)	250	(10)	(97)	—	—	(107)
Mark-to-market derivative liability with affiliate (noncurrent liabilities)	—	—	—	—	—	(191)	—	191	—
Total mark-to-market derivative liabilities	$ (13)	$(1,151)	$(264)	$ 1,315	$ (113)	$(800)	$—	$ 694	$ (219)
Total mark-to-market derivative net assets (liabilities)	$1,538	$ 626	$ 24	$ (540)	$1,648	$(800)	$ 15	$ —	$ 863

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $503 million and $191 million, respectively, related to the fair value of the five-year financial swap contract between Generation and ComEd, as described above. For Generation, excludes $19 million non current liability relating to an interest rate swap in connection with a loan agreement to fund Antelope Valley as discussed above.
(b) Represents the netting of fair value balances with the same counterparty and the application of collateral.
(c) Current and noncurrent assets are shown net of collateral of $338 million and $187 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $15 million and $0 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark-to-market assets and liabilities was $540 million at December 31, 2011.
(d) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges. Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. As discussed previously, effective prior to the merger with Constellation, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. The net unrealized gains associated with the de-designated cash flow hedges prior to the merger was $1,928 million including $693 million related to the intercompany swap with ComEd. Approximately $684 million of these net pre-tax unrealized gains within accumulated OCI are expected to be reclassified from accumulated OCI during the next twelve months by Generation, including approximately $219 million related to the financial swap with ComEd. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2013 through 2014.

Exelon discontinues hedge accounting prospectively when it determines that the derivative is no longer effective in offsetting changes in the cash flows of a hedged item or when it is no longer probable that the forecasted transaction will occur. For the years ended December 31, 2012 and 2011, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

The table below provides the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2012 and 2011, containing information about the changes in the fair value of cash flow hedges and the reclassification from accumulated OCI into results of operations. The amounts reclassified from accumulated OCI, when combined with the impacts of the actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
	Income Statement Location	Energy Related Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at January 1, 2011		$1,011[(a)(d)]	$ 400
Effective portion of changes in fair value		504[(b)]	402[(e)]
Reclassifications from accumulated OCI to net income	Operating Revenues	(585)[(c)]	(309)
Ineffective portion recognized in income	Purchased Power	(5)	(5)
Accumulated OCI derivative gain at December 31, 2011		925[(a)(d)]	488
Effective portion of changes in fair value		432[(b)]	330[(e)]
Reclassifications from accumulated OCI to net income	Operating Revenues	(828)[(c)]	(453)
Ineffective portion recognized in income	Operating Revenues	3	3
Accumulated OCI derivative gain at December 31, 2012		$ 532[(a)(d)]	$ 368

(a) Includes $133 million, $420 million and $589 million of gains, net of taxes, related to the fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012, 2011 and 2010, respectively, and $3 million of gains, net of taxes, related to the fair value of the block contracts with PECO for the year ended December 31, 2010.

(b) Includes $88 million and $104 million of gains, net of taxes, related to the effective portion of changes in fair value of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011, respectively, and $2 million of gains, net of taxes, of the effective portion of changes in fair value of the block contracts with PECO for the year ended December 31, 2010. As of the merger date, cash flow hedges were discontinued, as such, this amount represents changes in fair value prior to the merger date.

(c) Includes $375 million and $273 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the five-year financial swap contract with ComEd for the years ended December 31, 2012 and 2011, respectively, and $3 million of losses, net of taxes, reclassified from accumulated OCI to recognize gains in net income related to settlements of the block contracts with PECO for the year ended December 31, 2011.

(d) Excludes $20 million of losses and $10 million of losses, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2012 and 2011, respectively.

(e) Includes $9 million and $12 million of losses, net of taxes, related to the effective portion of changes in fair value of interest rate swaps and treasury rate locks at Generation for the year ended December 31, 2012 and 2011, respectively.

During the years ended December 31, 2012, 2011, and 2010 Generation's cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $1,368 million, $968 million and $1,125 million pre-tax gain, respectively. Given that the cash flow hedges had primarily consisted of forward power sales and power swaps and did not include power and gas options or sales, the ineffectiveness of Generation's cash flow hedges was primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference was actively managed through other instruments, which include financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices were losses of $5 million and gains of $10 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Exelon's energy-related cash flow hedge activity impact to pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a $747 million pre-tax gain for the year ended December 31, 2012, and a $512 million and $754 million pre-tax gain for the years ended 2011 and 2010, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were losses of $5 million and gains of $10 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Neither Exelon nor Generation will not incur changes in cash flow hedge ineffectiveness in future periods as all commodity cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges. These instruments represent hedges that mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, and physical forward sales and purchases. For the years ended December 31, 2012, 2011 and 2010, the following net pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense at Exelon in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's Consolidated Statements of Cash Flows. In the 3rd quarter of 2012, Generation completed a non-cash exchange by issuing a new in-the-money derivative with a new counterparty in exchange for novating to them existing in-the-money trades with the old counterparty for a total of $51 million. This transaction did not have any Income Statement effect to Generation. In the tables below, “Change in fair value” represents the change in fair value of the derivative contracts held at the reporting date. The “Reclassification to realized at settlement” represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Generation			Intercompany Eliminations	Exelon
Year Ended December 31, 2012	**Operating Revenues**	**Purchased Power and Fuel**	**Total**	**Operating Revenues**[(a)]	**Total**
Change in fair value	$(362)	$215	$(147)	$ (94)	$(241)
Reclassification to realized at settlement	429	238	667	101	768
Net mark-to-market gains (losses)	$ 67	$453	$ 520	$ 7	$ 527

Year Ended December 31, 2011 (As Reported)	**Operating Revenues**	**Purchased Power and Fuel**	**Total**
Change in fair value	$ 87	$ 131	$ 218
Reclassification to realized at settlement	(296)	(219)	(515)
Net mark-to-market (losses) [(b)]	$(209)	$ (88)	$(297)

Year Ended December 31, 2011 (Pro Forma)	**Operating Revenues**	**Purchased Power and Fuel**	**Total**
Change in fair value	$ 258	$ (40)	$ 218
Reclassification to realized at settlement	(516)	1	(515)
Net mark-to-market (losses) [(b)]	$(258)	$ (39)	$(297)

Year Ended December 31, 2010 (As Reported)	**Operating Revenues**	**Purchased Power and Fuel**	**Total**
Change in fair value	$ —	$ 389	$ 389
Reclassification to realized at settlement	—	(304)	(304)
Net mark-to-market (losses) [(b)]	$ —	$ 85	$ 85

(a) Prior to the merger, the five-year financial swap contract between Generation and ComEd was de-designated. As a result, all prospective changes in fair value are recorded to operating revenues and eliminated in consolidation.
(b) Exelon has historically presented mark-to-market gains and losses within purchased power expense for all non-trading, energy-related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon classified the mark-to-market gains and losses for contracts, where the underlying hedged transaction was an expected sale to hedge power, to operating revenues.

Proprietary Trading Activities. For the years ended December 31, 2012, and 2011, Exelon recognized the following net unrealized mark-to-market gains (losses), net realized mark-to-market gains (losses) and total net mark-to-market gains (losses) (before income taxes) relating to mark-to-market activity on derivative instruments entered into for proprietary trading purposes. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon’s Consolidated Statements of Operations and Comprehensive Income and are included in “Net fair value changes related to derivatives” in Exelon’s Consolidated Statements of Cash Flows. In the tables below, “Change in fair value” represents the change in fair value of the derivative contracts held at the reporting date. The “Reclassification to realized at settlement” represents the recognized change in fair value that was reclassified to realized due to settlement of the derivative during the period.

	Location on Income Statement	**For the Years Ended December 31,**		
		2012	**2011**	**2010**
Change in fair value	Operating Revenue	$ (12)	$ 23	$ 26
Reclassification to realized at settlement	Operating Revenue	108	(26)	(24)
Net mark-to-market gains	Operating Revenue	$ 96	$ (3)	$ 2

Credit Risk

Exelon would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation's exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation's credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2012. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the tables below do not include credit risk exposure from uranium procurement contracts or exposure through exchanges (i.e. NYMEX, ICE), further discussed in Quantitative and Qualitative Disclosures about Market Risk. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd, PECO and BGE of $54 million, $56 million and $31 million, respectively.

Rating as of December 31, 2012	Total Exposure Before Credit Collateral	Credit Collateral (a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$1,984	$347	$1,637	1	$262
Non-investment grade	28	24	4	—	—
No external ratings					
Internally rated—investment grade	512	10	502	1	271
Internally rated—non-investment grade	41	3	38	—	—
Total	$2,565	$384	$2,181	2	$533

Net Credit Exposure by Type of Counterparty	December 31, 2012
Investor-owned utilities, marketers and power producers	$ 865
Energy cooperatives and municipalities	786
Financial Institutions	422
Other	108
Total	$2,181

(a) As of December 31, 2012, credit collateral held from counterparties where Generation had credit exposure included $344 million of cash and $40 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of December 31, 2012, ComEd's credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation as well as the ICC-approved procurement tariffs. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for further information.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2012, PECO had no net credit exposure with suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for further information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $20 million in parental guarantees related to these agreements. As of December 31, 2012, PECO had credit exposure of $7 million under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3—Regulatory Matters for further information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The seller's credit exposure is calculated each business day. As of December 31, 2012, BGE had no net credit exposure with suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers' demands, which are not covered by the gas cost adjustment clause. At December 31, 2012, BGE had credit exposure of $8 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third party suppliers.

Collateral and Contingent-Related Features

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

Credit-Risk Related Contingent Feature		December 31, 2012
Gross Fair Value of Derivative Contracts Containing this Feature (a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements (b)**	**Net Fair Value of Derivative Contracts Containing This Feature (c)**
($1,849)	$1,426	($423)

Credit-Risk Related Contingent Feature		December 31, 2011
Gross Fair Value of Derivative Contracts Containing this Feature (a)	**Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements (b)**	**Net Fair Value of Derivative Contracts Containing This Feature (c)**
($1,014)	$928	($86)

(a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk-related contingent features that are not fully collateralized by posted cash collateral on an individual, contract-by-contract basis ignoring the effects of master netting agreements.

(b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.

(c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation has cash collateral posted of $527 million and letters of credit posted of $563 million and cash collateral held of $499 million and letters of credit held of $45 million as of December 31, 2012 and cash collateral held of $542 million and letters of credit held of $89 million at December 31, 2011. In the event of a credit downgrade below investment grade (i.e. BB+ or Ba1), Exelon Generation Company, LLC and Constellation Energy Commodities Group, Inc. could be required to post additional collateral of $1,920 million as of December 31, 2012, and $1,612 million as of December 31, 2011. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if their debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of December 31, 2012, Generation's and Exelon's swaps were in an asset position, with a fair value of $17 million and $30 million, respectively. See Note 21—Segment Information for further information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of the financial swap contract between Generation and ComEd, if a party is downgraded below investment grade by Moody's or S&P, collateral postings would be required by that party depending on how market prices compare to the benchmark price levels. Under the terms of the financial swap contract, collateral postings will never exceed $200 million from either ComEd or Generation. Under the terms of ComEd's standard block energy contracts, collateral postings are one-sided from suppliers, including Generation, should exposures between market prices and benchmark prices exceed established unsecured credit limits outlined in the contracts. As of December 31, 2012, ComEd held neither cash nor letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of December 31, 2012, ComEd held approximately $19 million in the form of cash and letters of credit as margin for both the annual and long-term REC obligations. See Note 1—Significant Accounting Policies for further information.

PECO's natural gas procurement contracts contain provisions that could require PECO to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon PECO's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2012, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2012, PECO could have been required to post approximately $35 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of December 31, 2012, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of December 31, 2012, BGE could have been required to post approximately $124 million of collateral to its counterparties.

Accounting for the Offsetting of Amounts Related to Certain Contracts

As of December 31, 2012, and December 31, 2011, $3 million and $2 million, respectively, of cash collateral received was not offset against derivative positions because they were not associated with energy-related derivatives.

11. Debt and Credit Agreements

Short-Term Borrowings

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

The Registrants had the following amounts of commercial paper borrowings at December 31, 2012 and 2011:

	Maximum Program Size at December 31,		Outstanding Commercial Paper at December 31,		Average Interest Rate on Commercial Paper Borrowings for the Year Ended December 31,	
Commercial Paper Issuer	**2012 (a)**	**2011 (a)**	**2012**	**2011**	**2012**	**2011**
Exelon Corporate	$ 500	$ 500	$—	$161	0.47%	0.42%
Generation	5,600	5,600	—	—	0.45%	0.48%
ComEd	1,000	1,000	—	—	0.50%	0.71%
PECO	600	600	—	—	—	—
BGE	600	400	—	—	0.43%	0.38%
Total	$8,300	$8,100	$—	$161		

(a) Equals aggregate bank commitments under revolving and bilateral credit agreements. See discussion below and Credit Agreements table below for items affecting effective program size.

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have revolving credit facilities in place, at least equal to the amount of its commercial paper program. While the amount of its outstanding commercial paper does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the then available capacity under its credit agreement.

At December 31, 2012, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under their respective credit agreements:

				Available Capacity at December 31, 2012	
Borrower	**Aggregate Bank Commitment** [(a)]	**Facility Draws**	**Outstanding Letters of Credit**	**Actual**	**To Support Additional Commercial Paper**
Exelon Corporate	$ 500	$—	$ 2	$ 498	$ 498
Generation	5,600	—	1,818	3,782	3,782
ComEd	1,000	—	—	1,000	1,000
PECO	600	—	1	599	599
BGE	600	—	—	600	600
Total	$8,300	$—	$1,821	$6,479	$6,479

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of $50 million, $34 million, $34 million and $5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 19, 2013 and are solely for issuing letters of credit. As of December 31, 2012, letters of credit issued under these agreements totaled $23 million, $21 million, $21 million and $1 million for Generation, ComEd, PECO and BGE, respectively.

For the year ended December 31, 2012, there were no borrowings under the Registrants' credit facilities.

The following tables present the short-term borrowings activity for Exelon during 2012, 2011 and 2010.

	2012	**2011**	**2010**
Average borrowings	$ 199	$ 218	$ 125
Maximum borrowings outstanding	505	600	346
Average interest rates, computed on a daily basis	0.48%	0.50%	0.72%
Average interest rates, at December 31	n.a.	0.44%	n.a.

Credit Agreements

In connection with the Upstream Merger, Exelon assumed all of Constellation's obligations under its three-year, unsecured revolving credit facility (the "Constellation Credit Agreement"). Effective as of the Initial Merger, the Constellation Credit Agreement was amended and restated to (1) permit Exelon and Constellation to consummate the Upstream Merger and the restructuring transaction, (2) reduce the aggregate commitments under the Constellation Credit Agreement from $2.5 billion to $1.5 billion, and (3) conform some of the representations, warranties, covenants and events of default in the Constellation Credit Agreement with representations, warranties, covenants and events of default in the Exelon credit agreement, dated as of March 23, 2011, as amended as of the Initial Merger. In connection with the Upstream Merger, Exelon also assumed Constellation's obligations under four separate bilateral credit facilities and a commodity-linked credit facility, which were also amended to conform with the Constellation Credit Agreement effective as of the Initial Merger. Effective as of the Initial Merger, the Exelon Credit Agreement and the Generation Credit Agreement were amended and restated to conform some of the representations, warranties and covenants with provisions of the Constellation Credit Agreement, as amended effective as of the Initial Merger. Exelon Corporation (as successor to Constellation Energy Group) entered into an amendment to the Amended and Restated Credit Agreement dated March 12, 2012, which changed the maturity date to December 31, 2012. See Note 4—Merger and Acquisitions for further description of the merger transaction.

On August 10, 2012, Exelon Corporate, Generation, PECO and BGE amended and extended their respective unsecured syndicated revolving credit facilities, with aggregate bank commitments of $500 million, $5.3 billion, $600 million and $600 million, respectively, through August 10, 2017. Under these facilities, Exelon Corporate, Generation, PECO and BGE may issue letters of credit in the aggregate of up to $200 million, $3.5 billion, $300 million and $600 million, respectively. Each credit facility permits the applicable borrower to request extensions for up to two additional one-year periods. Each credit facility also allows Exelon Corporate, Generation, PECO and BGE to request increases in aggregate commitments up to an additional $250 million, $1.0 billion, $250 million and $100 million, respectively. Any extension or increase of a credit facility is subject to the approval of the lenders party to that credit facility in their sole discretion. Costs incurred to amend and extend the facilities for Exelon Corporate, Generation, PECO and BGE were not material.

On March 28, 2012, ComEd replaced its unsecured revolving credit facility with a new unsecured facility with aggregate bank commitments of $1.0 billion. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $500 million. The credit agreement has an initial term expiring on March 28, 2017, and ComEd may request up to two, one-year extensions of that term. The credit facility also allows ComEd to request increases in the aggregate commitments of up to an additional $500 million. Any such extensions or increases are subject to the approval of the lenders party to the credit agreement in their sole discretion. Costs incurred to replace the credit facility for ComEd were not material.

Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon the prime rate or at a fixed rate for a specified period based upon a LIBOR-based rate. As of December 31, 2012, Exelon Corporate, Generation, PECO and BGE have adders of up to 27.5, 7.5, 0.0 and 7.5 basis points for prime based borrowings and 127.5, 107.5, 100.0 and 107.5 basis points for LIBOR-based borrowings, respectively. The fee varies depending upon the respective credit ratings of each entity. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings are 65 basis points and 165 basis points, respectively. The amended covenants in the amended credit facilities are substantially consistent with the covenants in the prior facilities, with the exception of BGE, which replaced its debt to capitalization covenant with an interest coverage ratio.

On October 19, 2012, Generation, ComEd and PECO replaced their expiring minority and community bank credit facilities with new minority and community bank credit facility agreements in the amounts of $50 million, $34 million and $34 million, respectively, and BGE entered into a minority and community bank credit facility in the amount of $5 million. These facilities, which expire in October 2013, are solely utilized by the applicable Registrants to issue letters of credit.

On January 23, 2013, Generation entered into a two year $75 million bilateral letter of credit facility with a bank. This facility will solely be utilized by Generation to issue letters of credit.

An event of default under any of the Registrants' credit facilities would not constitute an event of default under any of the other Registrants' credit facilities, except that a bankruptcy or other event of default in the payment of principal, premium or indebtedness in principal amount in excess of $100 million in the aggregate by Generation under its credit facility would constitute an event of default under the Exelon corporate credit facility.

Each credit facility requires the affected borrower to maintain a minimum cash from operations to interest expense ratio for the twelve-month period ended on the last day of any quarter. The ratios exclude revenues and interest expenses attributable to securitization debt, certain changes in working capital, distributions on preferred securities of subsidiaries and, in the case of Exelon and Generation, interest on the debt of its project subsidiaries. The following table summarizes the minimum thresholds reflected in the credit agreements for the year ended December 31, 2012:

	Exelon	Generation	ComEd	PECO	BGE
Credit facility threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2012, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	9.62	14.20	6.14	7.85	5.16

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its accounts receivable designated under the agreement in exchange for proceeds of $225 million. As of December 31, 2012 and 2011, the financial institution's undivided interest in PECO's gross accounts receivable was equivalent to $289 million and $329 million, respectively, which represents the financial institution's interest in PECO's eligible receivables as calculated under the terms of the agreement. The agreement requires PECO to maintain eligible receivables at least equivalent to the financial institution's undivided interest. Upon termination or liquidation of this agreement, the financial institution is entitled to recover up to $225 million plus the accrued yield payable from its undivided interest in PECO's receivables. On August 31, 2012, PECO entered into an Amendment to extend this agreement until August 30, 2013. This Amendment also expands the definition of a tariff receivable to include receivables that have been purchased by PECO and paid for in accordance with the Tariff and revises the compliance criteria for the eligible asset test to allow for the payment of capital within a specified period of time. On November 28, 2012, PECO made a principal paydown of $15 million to meet the eligible asset test requirement of the agreement for the October 2012 reporting period. The remaining principal balance of $210 million is classified as a short-term note payable on Exelon's Consolidated Balance Sheets. As of December 31, 2012, PECO was in compliance with the requirements of the agreement. In the event the agreement is not further extended, PECO has sufficient short-term liquidity and may seek alternate financing.

Long-Term Debt

On June 18, 2012, Generation issued and sold $775 million of Senior Notes. In connection with this debt issuance, Generation entered into forward-starting interest rate swaps in the aggregate notional amount of $470 million. The interest rate swaps were settled on June 15, 2012 with Generation recording a pre-tax loss of approximately $7 million. The loss was recorded to other comprehensive income within Exelon's Consolidated Balance Sheets and is being amortized to income over the life of the related debt as an increase to interest expense.

Concurrently with the new debt issuance, Generation engaged in private offers (the Exchange Offer) to certain eligible holders to exchange any and all of the $700 million outstanding 7.60% Senior Notes due 2032 (Old Notes) of Exelon (which were assumed by Exelon in the merger with Constellation), for:

- Generation's newly issued 4.25% Senior Notes due 2022, plus a cash payment; and
- Generation's newly issued 5.60% Senior Notes due 2042, plus a cash payment.

On June 28, 2012, pursuant to the Exchange Offer, Generation purchased $441 million of the Old Notes in exchange for issuing $535 million of Notes due in 2022 and 2042, plus a cash payment of approximately $60 million. The $441 million of Old Notes were recorded on Exelon's Consolidated Balance Sheets at $608 million, reflecting a fair value adjustment pursuant to the application of purchase accounting applied as a result of the Constellation merger which resulted in approximately $13 million gain from the Exchange Offer at Generation. The gain was recorded as an increase to Long-term Debt within Exelon's Consolidated Balance Sheets and will be amortized to income over the life of the debt as a reduction in interest expense.

On July 13, 2012, pursuant to the Exchange Offer described above, Generation purchased an additional $1 million of Old Notes in exchange for the Senior Notes due in 2022 and 2042.

In connection with the debt obligations assumed by Exelon as part of the Upstream Merger on March 12, 2012, Exelon and subsidiaries of Generation (former Constellation subsidiaries) assumed intercompany loan agreements that mirror the terms and amounts of the third-party debt obligations of Exelon, resulting in intercompany notes payable included in Long-term Debt to affiliate on Generation's Consolidated Balance Sheets in Exelon's 2012 Form 10-K and intercompany notes receivable at Exelon Corporate, which are eliminated in consolidation on Exelon's Consolidated Balance Sheets. The third-party debt obligations are reported in Long-term Debt on Exelon's Consolidated Balance Sheets. The intercompany loan agreements are summarized as follows:

- $700 million aggregate principal amount of Old Notes, $258 million of which was outstanding as of December 31, 2012 after the Exchange Offer described above;
- $550 million aggregate principal amount of 4.55% Fixed-Rate Notes due 2015, all of which was outstanding as of December 31, 2012;
- $450 million aggregate principal amount of 8.625% Series A Junior Subordinated Debentures due 2063, all of which was outstanding as of December 31, 2012; and
- $550 million aggregate principal amount of 5.15% Notes due 2020, all of which was outstanding as of December 31, 2012.

The intercompany loan agreements and the third-party debt obligations described above were increased by $403 million for a fair value adjustment pursuant to the application of purchase accounting applied as a result of the Constellation merger, of which $199 million was outstanding as of December 31, 2012, primarily reflecting the Exchange Offer described above and amortization of purchase accounting adjustment, which is being amortized over the lives of the arrangements as a reduction to interest expense.

In November 2012, Generation filed a registration statement on Form S-4 to register senior notes to be issued in connection with an exchange offer for the senior notes that were privately issued in June and July 2012. The exchange offer was consummated on February 19, 2013. The registered notes have the same terms and maturity dates as the privately placed senior notes.

The following table presents the outstanding long-term debt at Exelon as of December 31, 2012 and 2011:

	Rates	Maturity Date	December 31, 2012	December 31, 2011
Long-term debt				
First Mortgage Bonds [a] [b]:				
Fixed rates	1.63% — 7.63%	2012-2042	$ 7,397	$ 7,522
Unsecured bonds:	2.80% — 6.35%	2013-2036	1,850	—
Rate stabilization bonds:	5.72% — 5.82%	2017	332	—
Senior unsecured notes	2.00% — 8.63%	2014-2063	8,021	4,902
Notes payable and other [c]	6.95% — 7.83%	2012-2020	177	174
Pollution control notes:				
Fixed rates	4.10% — 5.00%	2014-2042	20	46
Non-recourse debt:				
Fixed rates	2.33% — 5.50%	2031-2037	238	—
Variable rates	1.96% — 2.77%	2014-2030	262	—
Total long-term debt			18,297	12,644
Unamortized debt discount and premium, net			(17)	(32)
Fair value adjustment			448	—
Fair value hedge carrying value adjustment, net			17	15
Long-term debt due within one year			(1,047)	(828)
Long-term debt			$17,698	$11,799
Long-term debt to financing trusts [d]				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206
Subordinated debentures to PECO Trust III	7.38%	2028	81	81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Subordinated debentures to BGE Trust	6.20%	2043	258	—
Total long-term debt to financing trusts			$ 648	$ 390

(a) Substantially all of ComEd's assets other than expressly excepted property and substantially all of PECO's assets are subject to the liens of their respective mortgage indentures.
(b) Includes First Mortgage Bonds issued under the ComEd and PECO mortgage indentures securing pollution control bonds and notes.
(c) Includes capital lease obligations of $30 million and $34 million at December 31, 2012 and 2011, respectively. Lease payments of $3 million, $3 million, $3 million, $4 million, $4 million and $13 million will be made in 2013, 2014, 2015, 2016, 2017 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon's Consolidated Balance Sheets.

Long-term debt maturities at Exelon in the periods 2013 through 2017 and thereafter are as follows:

Year	Exelon
2013	$ 979
2014	1,483
2015	1,613
2016	1,041
2017	1,462
Thereafter	12,367[a]
Total	$18,945

(a) Includes $648 million due to ComEd, PECO and BGE financing trusts.

Exelon Non-Recourse/Limited-Recourse Debt

The following are descriptions of certain indebtedness of Exelon's project subsidiaries that are outstanding as of December 31, 2012. The indebtedness described below is non-recourse to Exelon, unless otherwise noted.

Antelope Valley Project Development Debt Agreement

The DOE Loan Programs Office issued a guarantee for up to $646 million for a non-recourse loan from the Federal Financing Bank to support the financing of the construction of the Antelope Valley facility. The project is expected to be completed at the end of 2013. The loan will mature on January 5, 2037. Interest rates on the loan will be fixed upon each advance at a spread of 37.5 basis points above U.S. Treasuries of comparable maturity.

On April 5, 2012, Antelope Valley received the first DOE-guaranteed loan advance of $69 million. The loan advance terminated the put option that Generation had on the Antelope Valley project. Antelope Valley received additional advances subsequent to the initial advance, and as of December 31, 2012, has received $219 million in DOE-guaranteed funding. See Note 4—Merger and Acquisitions for additional information on Antelope Valley.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2012, Generation had $568 million in letters of credit outstanding related to the project The letters of credit balance is expected to decline over time as scheduled equity contributions for the project are made.

In connection with this agreement, Generation entered into a floating-for-fixed interest rate swap with a notional amount of $485 million to mitigate interest rate risk associated with the financing. As Generation received additional loan advances, they subsequently entered into a series of fixed-to-floating interest rate swaps to offset portions of the original interest rate hedge. See Note 10—Derivative Financial Instruments for additional information regarding interest rate swaps associated with Antelope Valley.

Sacramento PV Energy

In July, 2011, a subsidiary of Generation entered into a $41 million non-recourse project financing supported by a 30MW solar facility in Sacramento, California. As of December 31, 2012, $39 million was outstanding. Borrowings under the facility bear interest at a variable rate, payable quarterly, and are secured by equity interests and assets of the subsidiary. As of December 31, 2012, the subsidiary had interest rate swaps with a notional value of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $39 million facility. See Note 10—Derivative Financial Instruments for additional information regarding interest rate swaps.

Constellation Solar Horizons Financing

In September 2012, a subsidiary of Generation entered into an 18-year $38 million non-recourse variable interest note to recover capital used to build a 16MW solar facility in Emmitsburg, Maryland. Borrowing will incur interest at a variable rate, payable quarterly, and are secured by the equity interests and assets of the subsidiary. The subsidiary also executed interest rate swaps for a notional amount of $29 million in order to convert the variable interest payments to fixed payments on 75% of the $38 million facility amount. See Note 10—Derivative Financial Instruments for additional information regarding interest rate swaps.

Secured Solar Credit Lending Agreement. A subsidiary of Generation has a three-year senior secured credit facility that is designed to support the growth of solar operations. The amount committed under the facility is $150 million, which may be increased up to $200 million at the subsidiary's request with additional commitments by the lenders. As of December 31, 2012, $113 million was outstanding under the facility with interest payable quarterly. The facility is secured by the equity interests in the subsidiary and the entities that own the solar projects as well as the assets of the subsidiary and the projects' entities. The obligations of the subsidiary are guaranteed by Generation and the projects' entities. The Generation guarantee will terminate upon the subsidiary obtaining a stand-alone investment grade credit rating or the satisfaction of a number of conditions, at which time the financing will become non-recourse to and Generation.

Other Solar Project Financings. Generation has the following amounts outstanding under solar project loan agreements:

- $7 million fully amortizing by June 30, 2031 related to a solar project at the Denver International Airport, and
- $11 million fully amortizing by December 31, 2031 related to a solar project in Holyoke, Massachusetts.

Upstream Gas Property Asset-Based Lending Agreement

Generation has a three year asset-based lending agreement associated with certain upstream gas properties that it owns. The borrowing base committed under the facility is $150 million and can increase to a total of $500 million if the assets support a higher borrowing base and Generation is able to obtain additional commitments from lenders. The facility was amended and extended through July 2016. Borrowings under this facility are secured by the upstream gas properties, and the lenders do not have recourse against Exelon or Generation in the event of a default. As of December 31, 2012, $72 million was outstanding under the facility with interest payable quarterly. The facility includes a provision that requires Generation entities that own the upstream gas properties subject to the agreement to maintain a current ratio of one-to-one. As of December 31, 2012, Generation was in compliant with this provision.

12. Income Taxes

Income tax expense (benefit) from continuing operations is comprised of the following components:

	For the Year Ended December 31,		
	2012	2011	2010
Included in operations:			
Federal			
Current	$ 37	$ 1	$ 506
Deferred	701	1,200	972
Investment tax credit amortization	(11)	(12)	(12)
State			
Current	(25)	(3)	171
Deferred	(75)	271	21
Total	$627	$1,457	$1,658

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

For the Year Ended December 31, 2012 [a]	
U.S. Federal statutory rate	35.0%
Increase (decrease) due to:	
State income taxes, net of Federal income tax benefit	(3.6)
Qualified nuclear decommissioning trust fund income	5.4
Tax exempt income	(0.2)
Health care reform legislation	0.1
Amortization of investment tax credit, net deferred taxes	(1.1)
Production tax credits and other credits	(2.2)
Plant basis differences	(2.4)
Merger expenses [b]	2.4
Fines and Penalties	2.6
Other	(1.1)
Effective income tax rate	34.9%

For the Year Ended December 31, 2011	
U.S. Federal statutory rate	35.0%
Increase (decrease) due to:	
State income taxes, net of Federal income tax benefit	4.4
Qualified nuclear decommissioning trust fund income	0.5
Domestic production activities deduction	(0.3)
Tax exempt income	(0.2)
Health care reform legislation	(0.2)
Amortization of investment tax credit	(0.3)
Production tax credits	(0.9)
Plant basis differences	(1.0)
Other	(0.2)
Effective income tax rate	36.8%

For the Year Ended December 31, 2010

U.S. Federal statutory rate	35.0%
Increase (decrease) due to:	
State income taxes, net of Federal income tax benefit	3.0
Qualified nuclear decommissioning trust fund income	1.7
Domestic production activities deduction	(1.2)
Tax exempt income	(0.1)
Health care reform legislation	1.4
Amortization of investment tax credit	(0.3)
Plant basis differences	—
Uncertain tax position remeasurement	—
Other	(0.2)
Effective income tax rate	39.3%

(a) Exelon activity for the twelve months ended December 31, 2012 includes the results of Constellation and BGE for March 12, 2012—December 31, 2012.

(b) Prior to the close of the merger, Exelon recorded the applicable taxes on merger transaction costs assuming the merger would not be completed. Upon closing of the merger, Exelon reversed such taxes for those merger transaction costs that were determined to be non tax-deductible upon successful completion of a merger.

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2012 and 2011 are presented below:

For the Year Ended December 31, 2012

Plant basis differences	$(10,689)
Accrual based contracts	(389)
Derivatives and other financial instruments	(392)
Deferred pension and post-retirement obligation	1,225
Nuclear decommissioning activities	(604)
Deferred debt refinancing costs	(537)
Tax loss carryforward	421
Tax credit carryforward	226
Investment in CENG	(405)
Other, net	(25)
Deferred income tax liabilities (net)	$(11,169)
Unamortized investment tax credits	(251)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(11,420)

For the Year Ended December 31, 2011

Plant basis differences	$(7,803)
Unrealized gains on derivative financial instruments	(468)
Deferred pension and post-retirement obligation	665
Nuclear decommissioning activities	(452)
Deferred debt refinancing costs	(37)
Other, net	41
Deferred income tax liabilities (net)	$(8,054)
Unamortized investment tax credits	(200)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(8,254)

The following table provides Exelon's carryforwards and any corresponding valuation allowances as of December 31, 2012.

Federal	
Federal net operating loss	$ 635(a)
Federal capital loss carryforward	178(b)
Federal general business credits carryforward	226(c)
State	
State net operating loss	3,365(d)
State capital loss carryforward	127(e)
Deferred taxes on state tax attributes (net)	187
Valuation allowance on state tax attributes	36

(a) Exelon's federal net operating loss will expire beginning in 2033
(b) Exelon's federal capital loss carryforwards will expire beginning in 2018
(c) Exelon's federal general business credit carryforwards will expire beginning in 2033
(d) Exelon's state net operating losses will expire beginning in 2014
(e) Exelon's state capital loss carryforwards will expire beginning in 2018

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of Exelon's unrecognized tax benefits as of December 31, 2012, 2011 and 2010:

Unrecognized tax benefits at January 1, 2012	$ 807
Merger Balance Transfer	195
Increases based on tax positions related to 2012	34
Change to positions that only affect timing	(88)
Increases based on tax positions prior to 2012	91
Decreases based on tax positions prior to 2012	(6)
Decreases related to settlements with taxing authorities	(2)
Decreases from expiration of statute of limitations	(7)
Unrecognized tax benefits at December 31, 2012	$1,024
Unrecognized tax benefits at January 1, 2011	$ 787
Increases based on tax positions related to 2011	5
Change to positions that only affect timing	21
Decreases based on tax positions prior to 2011	(3)
Decrease from expiration of statute of limitations	(3)
Unrecognized tax benefits at December 31, 2011	$ 807
Unrecognized tax benefits at January 1, 2010	$1,498
Increases based on tax positions related to 2010	1
Decreases based on tax positions related to 2010	(2)
Change to positions that only affect timing	(262)
Increases based on tax positions prior to 2010	8
Decreases based on tax positions prior to 2010	(3)
Decreases related to settlements with taxing authorities	(452)
Decrease from expiration of statute of limitations	(1)
Unrecognized tax benefits at December 31, 2010	$ 787

Included in Exelon's unrecognized tax benefits balance at December 31, 2012 and 2011 are approximately $730 million and $804 million, respectively, of tax positions for which the ultimate tax benefit is highly certain, but for which there is uncertainty about the timing of such benefits. The disallowance of such positions would not materially affect the annual effective tax rate but would accelerate the payment of cash to, or defer the receipt of the cash tax benefit from, the taxing authority to an earlier or later period respectively.

Unrecognized tax benefits that if recognized would affect the effective tax rate

Exelon and Generation have $294 million and $263 million, respectively, of unrecognized tax benefits at December 31, 2012 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $3 million and $3 million, respectively, of unrecognized tax benefits at December 31, 2011 that, if recognized, would decrease the effective tax rate.

Total amounts of interest and penalties recognized

The following table represents the net interest receivable (payable), including interest related to uncertain tax positions reflected in Exelon's Consolidated Balance Sheets. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest receivable (payable) as of	
December 31, 2012	$31
December 31, 2011	74

The following table sets forth the net interest expense, including interest related to uncertain tax positions, recognized in interest expense (income) in other income and deductions in Exelon's Consolidated Statements of Operations. Exelon's has not accrued any penalties with respect to uncertain tax positions. Prior to the merger legacy Constellation recorded interest related to uncertain tax positions as a tax and not interest.

Net interest expense (income) for the years ended	
December 31, 2012	$ (1)
December 31, 2011	(56)
December 31, 2010	110

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and has disallowed the claims. In November 2008, Generation received a final determination from the Appeals division of the IRS (IRS Appeals) disallowing AmerGen's refund claims. On February 20, 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. In August 2009, the DOJ filed its answer denying the allegations made by Generation in its complaint. While the discovery phase of the litigation has been completed, no trial date has yet been assigned but could occur sometime in 2013.

During 2012, the parties agreed to take advantage of the court's Alternative Dispute Resolution (ADR) program in an effort to resolve the dispute. The court's ADR program provides a confidential and non-binding mediation process that tries to facilitate settlements. The parties participated in mediation discussions late in 2012 and these discussions are currently ongoing. Due to the possibility of quicker resolution through the ADR program, Generation believes that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next twelve months.

State Income Taxes

Generation has approximately $100 million of unrecognized tax benefits related to various state income tax return positions for which it is reasonably possible the unrecognized tax benefits could significantly change within 12 months due to the expiration of statutes of limitation or settlements with the state taxing authorities. Furthermore, Generation has approximately $55 million of unrecognized tax benefits related to state income tax refund claims that are currently being litigated. It is reasonably possible the unrecognized tax benefits of $55 million would decrease within 12 months.

See Other Tax Matters—Involuntary Conversion, Like Kind Exchange and Competitive Transition Charges section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

Description of tax years that remain subject to examination by major jurisdiction

Taxpayer	Open Years
Exelon (and predecessors) and subsidiaries consolidated Federal income tax returns	1999 - 2011
Constellation and subsidiaries consolidated Federal income tax returns	2005 - March 2012
Exelon and subsidiaries Illinois unitary income tax returns	2007 - 2011
Constellation combined New York corporate income tax returns	2008 - March 2012
Various separate company Pennsylvania corporate net income tax returns	2008 - March 2012
Various separate company Maryland corporate net income tax returns	2005 - March 2012

Other Tax Matters

Involuntary Conversion, Like-Kind Exchange and Competitive Transition Charges

1999 Sale of Fossil Generating Assets. Exelon, through its ComEd subsidiary, took two positions on its 1999 income tax return to defer approximately $2.8 billion of tax gain on the sale of ComEd's fossil generating assets. Exelon deferred approximately $1.6 billion of the gain under the involuntary conversion provisions of the IRC. Exelon believed that it was economically compelled to dispose of ComEd's fossil generating plants as a result of the Illinois Act and that the proceeds from the sale of the fossil plants were properly reinvested in qualifying replacement property such that the gain could be deferred over the lives of the replacement property under the involuntary conversion provisions. The remaining approximately $1.2 billion of the gain was deferred by reinvesting the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with both positions and asserted that the entire gain of approximately $2.8 billion was taxable in 1999.

Competitive Transition Charges. Exelon contended that the Illinois Act and the Competition Act resulted in the taking of certain of ComEd's and PECO's assets used in their respective businesses of providing electricity services in their defined service areas. Exelon filed refund claims with the IRS taking the position that CTCs collected during ComEd's and PECO's transition periods represent compensation for that taking and, accordingly, were excludible from taxable income as proceeds from an involuntary conversion. The tax basis of property acquired with the funds provided by the CTCs would be reduced such that the benefits of the position are temporary in nature. The IRS disallowed the refund claims for the 1999-2001 tax years.

Status of Involuntary Conversion and CTC Positions. In the second quarter of 2010, the IRS offered to settle the disagreement over the involuntary conversion and CTC positions. Exelon concluded, based on that offer, that it had sufficient new information that a remeasurement of the involuntary conversion and CTC positions was required in accordance with applicable accounting standards. As a result of the required remeasurement, Exelon recorded $65 million (after-tax) of interest expense, of which $36 million (after-tax) and $22 million (after-tax) were recorded at ComEd and PECO, respectively. ComEd also recorded a current tax expense of $70 million offset with a tax benefit recorded at Generation of $70 million. In the third quarter of 2010, Exelon and the IRS reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion on terms consistent with the settlement offer received in the second quarter. As a result of the preliminary agreement, Exelon and ComEd eliminated any liability for unrecognized tax benefits and established a current tax payable to the IRS. In November 2012, the IRS and Exelon finalized and executed definitive agreements to resolve Exelon's involuntary conversion and CTC positions. Exelon paid $302 million in late 2010 in advance of the final settlement and the assessment.

Status of Like-Kind Exchange Position. Exelon has been unable to reach agreement with the IRS regarding the dispute over the like kind exchange position.

The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a "listed transaction" that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately $86 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Exelon expects to initiate litigation in 2013 to contest the IRS's disallowance of the like-kind exchange position. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, as of

December 31, 2012, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it no longer meets the more-likely-than-not standard. As a result, Exelon expects to record in the first quarter of 2013 a non-cash charge to earnings of approximately $270 million, which represents the full amount of interest expense (after-tax) and incremental state tax expense in the event that Exelon is unsuccessful in litigation. Of this amount, approximately $185 million will be recorded at ComEd and the balance at Exelon. Exelon and ComEd will continue to accrue interest on the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. Further, Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As a result of this hold harmless agreement, ComEd will record on its consolidated balance sheet non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. The IRS also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like-kind exchange position. Exelon continues to believe that it is unlikely that the penalty assertion will ultimately be sustained and therefore no liability for the penalty has been recorded.

This determination for accounting purposes does not alter Exelon's intent to aggressively litigate the issue through appeals, if necessary, which could take three to five years. Exelon currently expects to initiate the litigation in the United States Tax Court, whose decisions are not controlled by the Federal Circuit's decision in Consolidated Edison.

As of March 31, 2013, in the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable may be as much as $860 million, of which approximately $320 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Accounting for Generation Repairs

In 2009, Exelon received approval from the IRS to change its method of accounting for repair costs associated with Generation's power plants. Although the IRS granted Exelon approval to change its method of accounting, the approval did not affirm the methodology used to calculate the deduction. In the second quarter of 2010, Exelon was informed that the IRS intended to issue broad industry guidance with respect to electric generation power plants. In anticipation of the issuance of this guidance, the IRS provided notice to Exelon in the third quarter of 2012 that it intended to apply the principles of Large Business & Industry Directive No. 4-0312-004, thereby deferring auditing Generation's repair deductions until after issuance of the industry guidance and after Exelon has had an opportunity to change its accounting method to conform to that new guidance. As a result, in the third quarter of 2012, Exelon reduced its unrecognized tax benefits by approximately $107 million with an offsetting increase to its deferred tax liabilities and no net impact on results of operations.

The IRS is expected to issue industry guidance during 2013. Exelon will then determine the financial statement impacts of the generation repair costs accounting method change.

2011 Illinois State Tax Rate Legislation

The Taxpayer Accountability and Budget Stabilization Act, (SB 2505), enacted into law in Illinois on January 13, 2011, increases the corporate tax rate in Illinois from 7.3% to 9.5% for tax years 2011 – 2014, provides for a reduction in the rate from 9.5% to 7.75% for tax years 2015 – 2024 and further reduces the rate from 7.75% to 7.3% for tax years 2025 and thereafter. Pursuant to the rate change, Exelon reevaluated its deferred state income taxes during the first quarter of 2011. Illinois' corporate income tax rate changes resulted in a charge to state deferred taxes (net of Federal taxes) during the first quarter of 2011 of $7 million, $11 million and $4 million for Exelon, Generation and ComEd, respectively. Exelon's and ComEd's charge is net of a regulatory asset of $15 million.

In 2011, the income tax rate change increased Exelon's Illinois income tax provision (net of Federal taxes) by approximately $7 million, of which $12 million and $5 million of additional tax relates to Exelon Corporate and Generation, respectively, and a $10 million benefit for ComEd. The 2011 tax benefit at ComEd reflects the impact of a 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed below.

Long-Term State Tax Apportionment

Exelon and Generation periodically review events that may significantly impact how income is apportioned among the states and, therefore, the calculation of Exelon's and Generation's deferred state income taxes. In 2010, the Registrants performed a review of the long-term state tax rates and noted no significant events that would materially impact state apportionment. As such, there was no update to the long-term state apportionment rates in 2010. In 2011 as a result of the 2011 Illinois State Tax Rate Legislation discussed above, Exelon and Generation re-evaluated their long-term state tax apportionment for Illinois and all other states where they have state income tax obligations. The effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax expense during the first quarter of 2011 of $22 million and $11 million (net of Federal taxes) for Exelon and Generation, respectively. The long-term state tax apportionment also was revised in the fourth quarter of 2011 pursuant to long-term state tax apportionment policy, resulting in recording an additional deferred state tax expense of $1 million and a deferred state tax benefit of $8 million (net of Federal taxes) for Exelon and Generation, respectively.

As a result of the merger with Constellation, Exelon and Generation reevaluated their long-term state tax apportionment in the first quarter of 2012 for all states where they have state income tax obligations, which include Illinois, Maryland and Pennsylvania, as well as other states. The total effect of revising the long-term state tax apportionment resulted in the recording of a deferred state tax asset of $72 million (net of Federal taxes) for Exelon. Of this, a benefit in the amount of $116 million and $14 million (net of Federal taxes) was recorded for Exelon and Generation, respectively, for the three months ended March 31, 2012. Further, Exelon and Generation recorded deferred state tax liabilities of $44 million and $14 million (net of Federal taxes), respectively, as part of purchase accounting during the three months ended March 31, 2012. The long-term state tax apportionment also was updated in the fourth quarter of 2012, resulting in the recording of a deferred state tax benefit of $3 million (net of Federal taxes) for Exelon, and a deferred state tax expense of $7 million (net of Federal taxes) for Generation. There was no change to the long-term state tax apportionment for BGE, ComEd and PECO.

Accounting for Electric Transmission and Distribution Property Repairs

On August 19, 2011, the IRS issued Revenue Procedure 2011-43 providing a safe harbor method of tax accounting for repair costs associated with electric transmission and distribution property. ComEd and PECO adopted the safe harbor in the Revenue Procedure for the 2011 and 2010 tax years, respectively. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction to income tax expense at PECO, while Generation incurred additional income tax expense in the amount of $28 million due to a decrease in its manufacturer's deduction, which are reflected in the effective income tax rate reconciliation above in the plant basis differences and domestic production activities deduction lines, respectively. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor resulted in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million, $95 million respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million related to a decreased domestic production activities deduction.

BGE adopted the safe harbor for the short period 2012 pre-merger tax year. For the year ended December 31, 2012, the adoption of the safe harbor resulted in a cash tax benefit at BGE in the amount of $27 million.

See Note 3—Regulatory Matters for discussion of the regulatory treatment prescribed in the 2010 electric distribution rate case settlement for PECO's cash tax benefit resulting from the application of the method change to years prior to 2010.

Accounting for Gas Distribution Property Repairs

In September 2012, PECO filed an application with the IRS to change its method of accounting for gas distribution repairs for the 2011 tax year. The change to the newly adopted method for the 2011 tax year and 2012 resulted in a tax benefit of $26 million at Exelon, of which $29 million in tax benefit is recorded at PECO, partially offset by an expense recorded at Generation to reflect a reduction in its domestic production activities deduction. BGE changed its method of accounting for gas distribution repairs for the 2008 tax year. The IRS is expected to issue industry guidance during 2013. Exelon will then determine the financial statement impacts of the gas distribution repair costs accounting method changes.

Allocation of Tax Benefits

Generation, ComEd and PECO are all party to an agreement with Exelon and other subsidiaries of Exelon that provides for the allocation of consolidated tax liabilities and benefits (Tax Sharing Agreement). The Tax Sharing Agreement provides that each party is allocated an amount of tax similar to that which would be owed had the party been separately subject to tax. In addition, any net benefit attributable to Exelon is reallocated to the other Registrants. That allocation is treated as a contribution to the capital of the party receiving the benefit. During 2012, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $48 million and $9 million, respectively. During 2012, ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's 2012 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010. During 2011, Generation and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $30 million and $18 million, respectively. During 2011, ComEd did not record an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement as a result of ComEd's 2011 tax net operating loss generated primarily by the bonus depreciation deduction allowed under the Tax Relief Act of 2010 and the electric transmission and distribution property repairs deduction discussed above. During 2010, Generation, ComEd and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $60 million, $2 million and $43 million, respectively.

ComEd received a non-cash contribution to equity from Exelon in 2012 and 2011 of $11 million and $11 million, respectively, related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

13. Asset Retirement Obligations

Nuclear Decommissioning Asset Retirement Obligations

Generation has a legal obligation to decommission its nuclear power plants following the expiration of their operating licenses. To estimate its decommissioning obligation related to its nuclear generating stations, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's Consolidated Balance Sheets, from January 1, 2011 to December 31, 2012:

Nuclear decommissioning ARO at January 1, 2011	$3,276
Accretion expense	209
Net increase due to changes in, and timing of, estimated future cash flows	198
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2011 [(a)]	3,680
Accretion expense	231
Net increase due to changes in, and timing of, estimated future cash flows	833
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2012 [(a)]	$4,741

(a) Includes $10 million and $5 million as the current portion of the ARO at December 31, 2012 and 2011, respectively, which is included in other current liabilities on Exelon's Consolidated Balance Sheets.

During 2012, Generation's ARO increased by $1,061 million. The increase in the ARO is largely driven by the following four factors: i) changes in the timing of the future nominal cash flows resulting from an assumed five year deferral to 2025 of the acceptance date of spent nuclear fuel by the DOE coupled with the fact that; ii) cash flows affected by this change in timing are re-measured and discounted at current credit adjusted risk free rates (CARFRs), which have dramatically decreased given the current low interest rate environment; iii) an increase in the estimated costs to decommission the Quad Cities, Dresden and Clinton nuclear units resulting from the completion of updated decommissioning costs studies received during 2012; and iv) accretion of the obligation. The increase in the ARO due to the changes in estimated cash flows resulted in $10 million of expense, which is included in Exelon's Consolidated Statements of Operations and Comprehensive Income.

During 2011, Generation recorded a net increase in the ARO of $404 million primarily due to increases for accretion and an increase in the estimated costs to decommission the Oyster Creek and Zion nuclear units resulting from the completion of updated decommissioning cost studies received in 2011 and an increase in the expected long-term escalation rates for energy, partially offset by decreases in long-term escalation rates for labor and other costs as compared to prior study periods. The increase in the Zion nuclear unit ARO resulted in $28 million of expense, which is included in Exelon's Consolidated Statements of Operations and Comprehensive Income, as the Zion nuclear unit is retired, and as such, is unable to record increases to the ARO through an ARC. Additionally, the Zion nuclear unit is not subject to a regulatory agreement that would provide for offset of the expense.

Zion Station Decommissioning

On September 1, 2010, Generation completed an Asset Sale Agreement (ASA) with EnergySolutions Inc. and its wholly owned subsidiaries, EnergySolutions, LLC (EnergySolutions) and ZionSolutions under which ZionSolutions has assumed responsibility for decommissioning Zion Station, which is located in Zion, Illinois and ceased operation in 1998. 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. On January 7, 2013, EnergySolutions announced that it had entered a definitive acquisition agreement to be acquired by another company. Generation has reviewed the acquisition as it relates to the ASA to decommission Zion Station. Based on that review, Generation determined that the acquisition will not adversely impact decommissioning activities under the ASA.

On July 14, 2011, three people filed a purported class action lawsuit in the United States District Court for the Northern District of Illinois naming ZionSolutions and Bank of New York Mellon as defendants and seeking, among other things, an accounting for use of NDT funds, an injunction against the use of NDT funds, the appointment of a trustee for the NDT funds, and the return of NDT funds to customers of ComEd to the extent legally entitled thereto. If the plaintiffs prevail on the merits of their claims, some or all of the NDT funds may no longer be available to ZionSolutions for decommissioning Zion Station, in which case, the contractual arrangement would require ZionSolutions to utilize a line of credit to complete the decommissioning. In addition, the appointment of a NDT fund trustee in this matter could impact Generation's future decommissioning activities at other stations by setting a precedent for the appointment of trustees for NDT funds. On July 20, 2012, ZionSolutions and Bank of New York Mellon filed a motion to dismiss the amended complaint for failing to state a claim. The matter is currently under review by the court.

ZionSolutions is subject to certain restrictions on its ability to request reimbursements from the Zion Station NDT funds as defined within the ASA. Therefore, the transfer of the Zion Station assets did not qualify for asset sale accounting treatment and, as a result, the related NDT funds were reclassified to pledged assets for Zion Station decommissioning within Exelon's Consolidated Balance Sheets and will continue to be measured in the same manner as prior to the completion of the transaction. Additionally, the transferred ARO for decommissioning was replaced with a payable to ZionSolutions in Exelon's Consolidated Balance Sheets. Changes in the value of the Zion Station NDT assets, net of applicable taxes, will be recorded as a change in the payable to ZionSolutions. At no point will the payable to ZionSolutions exceed the project budget of the costs remaining to decommission Zion Station. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers. Generation has retained its obligation to transfer the SNF at Zion Station to the DOE for ultimate disposal and has a liability of approximately $79 million and $65 million at December 31, 2012 and 2011, respectively, which is included within the nuclear decommissioning ARO. Generation also has retained NDT assets to fund its obligation to maintain and transfer the SNF at Zion Station. The following table provides the pledged assets and payable to ZionSolutions, and withdrawals by ZionSolutions at December 31, 2012 and 2011:

	2012	2011
Carrying value of Zion Station pledged assets	$614	$734
Payable to Zion Solutions [(a)]	564	691
Current portion of payable to Zion Solutions [(b)]	132	128
Withdrawals by Zion Solutions to pay decommissioning costs	192	143

(a) Excludes a liability recorded within Exelon's Consolidated Balance Sheets related to the tax obligation on the unrealized activity associated with the Zion Station NDT Funds. The NDT Funds will be utilized to satisfy the tax obligations as gains and losses are realized.

(b) Included in other current liabilities within Exelon's Consolidated Balance Sheets.

ZionSolutions leased the land associated with Zion Station from Generation pursuant to a Lease Agreement. Under the Lease Agreement, ZionSolutions has committed to complete the required decommissioning work according to an established schedule and will construct a dry cask storage facility on the land for the SNF currently held in SNF pools at Zion Station. Rent payable under the Lease Agreement is $1.00 per year, although the Lease Agreement requires ZionSolutions to pay property taxes associated with Zion Station and penalty rents may accrue if there are unexcused delays in the progress of decommissioning work at Zion Station or the construction of the dry cask SNF storage facility. To reduce the risk of default by EnergySolutions or ZionSolutions, EnergySolutions provided a $200 million letter of credit to be used to fund decommissioning costs in the event the NDT assets are insufficient. EnergySolutions has also provided a performance guarantee and entered into other agreements that will provide rights and remedies for Generation and the NRC in the case of other specified events of default, including a special purpose easement for disposal capacity at the EnergySolutions site in Clive, Utah, for all LLRW volume of Zion Station.

Nuclear Decommissioning Trust Fund Investments

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. NDT funds established for a particular unit may not be used to fund the decommissioning obligations of any other unit.

The NDT funds associated with the former ComEd, former PECO and former AmerGen units have been funded with amounts collected from ComEd customers, PECO customers and the previous owners of the former AmerGen plants, respectively. Based on an ICC order, ComEd ceased collecting amounts from its customers to pay for decommissioning costs. PECO currently collects funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are expected to continue through the operating lives of the plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds. Every five years, PECO files a rate adjustment with the PaPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual collections of $24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. With respect to the former AmerGen units, Generation does not collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from customers. Apart from the contributions made to the NDT funds from amounts collected from ComEd and PECO customers, Generation has not made contributions to the NDT funds.

Any shortfall of funds necessary for decommissioning, determined for each generating station unit, is ultimately required to be funded by Generation. Generation has recourse to collect additional amounts from PECO customers related to a shortfall of NDT funds for the former PECO units, subject to certain limitations and thresholds, as prescribed by an order from the PAPUC. Generally, PECO will not be allowed to collect amounts associated with the first $50 million of any shortfall of trust funds, on an aggregate basis for all former PECO units, compared to decommissioning obligations, as well as 5% of any additional shortfalls. This initial $50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts from ComEd customers for the former ComEd units or from the previous owners of the former AmerGen units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after decommissioning has been completed are required to be refunded to ComEd's or PECO's customers, subject to certain limitations that allow sharing of excess funds with Generation related to the former PECO units. With respect to the former AmerGen units, Generation retains any funds remaining in the NDTs after decommissioning.

At December 31, 2012, and 2011, Exelon and Generation had NDT fund investments totaling $7,248 million and $6,507 million, respectively.

During 2012, the NDT fixed income portfolio completed its transition from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment-grade corporate credit and middle market lending. There was no change in the equity investment strategy. At December 31, 2012, approximately 47% of the funds were invested in equity securities and 53% were invested in fixed income securities. At December 31, 2011, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities.

NRC Minimum Funding Requirements. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts to decommission the facility at the end of its life. The estimated decommissioning obligations as calculated using the NRC methodology differ from the ARO recorded on Generation's and Exelon's Consolidated Balance Sheets primarily due to differences in the types of costs included in the estimates, the basis for estimating such costs, and assumptions regarding the decommissioning alternatives to be used, potential license renewals, decommissioning cost escalation, and the growth rate in the NDT funds. Under NRC regulations, if the minimum funding requirements calculated under the NRC methodology are less than the future value of the NDT funds, also calculated under the NRC methodology, then the NRC requires either further funding or other financial guarantees.

Key assumptions used in the minimum funding calculation using the NRC methodology at December 31, 2012 include: (1) consideration of costs only for the removal of radiological contamination at each unit; (2) the option on a unit-by-unit basis to use generic, non-site specific cost estimates; (3) consideration of only one decommissioning scenario for each unit; (4) the plants cease operation at the end of their current license lives (with no assumed license renewals for those units that have not already received renewals and with an assumed end-of-operations date of 2019 for Oyster Creek); (5) the assumption of current nominal dollar cost estimates that are neither escalated through the anticipated period of decommissioning, nor discounted using the CARFR; and (6) assumed annual after-tax returns on the NDT funds of 2% (3% for the former PECO units, as specified by the PAPUC).

In contrast, the key criteria and assumptions used by Generation to determine the ARO and to forecast the target growth in the NDT funds at December 31, 2012 include: (1) the use of site specific cost estimates that are updated at least once every five years; (2) the inclusion in the ARO estimate of all legally unavoidable costs required to decommission the unit (e.g., radiological decommissioning and full site restoration for certain units, on-site spent fuel maintenance and storage subsequent to ceasing operations and until DOE acceptance, and disposal of certain low-level radioactive waste); (3) the consideration of multiple scenarios where decommissioning activities are completed under three possible scenarios ranging from 10 to 70 years after the cessation of plant operations; (4) the assumption plants cease operating at the end of an extended license life (assuming 20-year license renewal extensions, except Oyster Creek with an assumed end-of-operations date of 2019); (5) the measurement of the obligation at the present value of the future estimated costs and an annual average accretion of the ARO of approximately 5% through a period of approximately 30 years after the end of the extended lives of the units; and (6) an estimated targeted annual pre-tax return on the NDT funds of 5.3% to 6.2% (as compared to a historical 5-year annual average pre-tax return of approximately 3.6%).

Generation is required to provide to the NRC a biennial report by unit (annually for units that have been retired or are within five years of the current approved license life), based on values as of December 31, addressing Generation's ability to meet the NRC minimum funding levels. Depending on the value of the trust funds, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or make additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Exelon's and Generation's cash flows and financial position may be significantly adversely affected.

On March 31, 2011, Generation, in its NRC-required biennial decommissioning funding status report, provided data from which the NRC concluded that the amount of decommissioning funding as of December 31, 2010 for Limerick Unit 1 was less than the amount required by the NRC's regulations. Generation performed the calculations again in early 2012, which reflected that the amount of decommissioning funding as of December 31, 2011, for Limerick Unit 1 was less than the amount required by the NRC's regulations. In February 2012, Generation obtained a parent guarantee in the amount of $115 million to cover the NRC minimum funding assurance requirements for Limerick Unit 1 and informed the NRC that it had addressed the minimum funding issues by, among other things, obtaining the parent guarantee. In a letter dated June 28, 2012, the NRC advised Generation of the NRC's determination that the amount of decommissioning financial assurance provided in Generation's plan was equal to or greater than the minimum required under the NRC regulations and that Generation had provided reasonable assurance that funds would be available for the Limerick Unit 1 decommissioning process.

On January 31, 2013, Generation received a letter from the NRC indicating that the NRC has identified potential "apparent violations" of its regulations because of alleged inaccuracies in the Decommissioning Fund Status reports for 2005, 2006, 2007, and 2009. The NRC asserted that Generation's status reports deliberately reflected cost estimates for decommissioning its nuclear plants that were less than what the NRC says are the minimum amounts required by NRC regulations. The NRC invited Generation to participate in a pre-decisional enforcement conference. At that conference, Generation will have an opportunity to explain its actions to the NRC. Generation will demonstrate that it did not deliberately or intentionally provide inaccurate or incomplete information in violation of the regulations and that it applied the regulatory provisions in a reasonable manner and in good faith. The letter from the NRC does not take issue with Generation's current funding status. The NRC has publicly confirmed that Generation is currently sufficiently funded for decommissioning activities. While Generation does not believe that any sanction is appropriate, the ultimate outcome of this proceeding including the amount of a potential fine or sanction, if any, is uncertain.

As the future values of trust funds change due to market conditions, the NRC minimum funding status of Generation's units will change. In addition, if changes occur to the regulatory agreement with the PAPUC that currently allows amounts to be collected from PECO customers for decommissioning the former PECO nuclear plants, the NRC minimum funding status of those plants could change at subsequent NRC filing dates.

Accounting Implications of the Regulatory Agreements with ComEd and PECO. Based on the regulatory agreement with the ICC that dictates Generation's obligations related to the shortfall or excess of NDT funds necessary for decommissioning the former ComEd units on a unit-by-unit basis, as long as funds held in the NDT funds exceed the total estimated decommissioning obligation, decommissioning-related activities, including realized and unrealized gains and losses on the NDT funds and accretion of the decommissioning obligation, are generally offset within Exelon's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, ComEd has recorded an equal noncurrent affiliate receivable from Generation and corresponding regulatory liability. Should the value of the NDT fund for any former ComEd unit fall below the amount of the estimated decommissioning obligation for that unit, the accounting to offset decommissioning-related activities in the Consolidated Statement of Operations and Comprehensive Income for that unit would be discontinued, the decommissioning-related activities would be recognized in the Consolidated Statements of Operations and Comprehensive Income and the adverse impact to Exelon's and Generation's results of operations and financial position could be material. At December 31, 2012, the NDT funds of each of the former ComEd units exceeded the related decommissioning obligation for each of the units. For the purposes of making this determination, the decommissioning obligation referred to is the ARO reflected on Generation's Consolidated Balance Sheet at December 31, 2012 in Exelon's 2012 Form 10-K and is different, as described above, from the calculation used in the NRC minimum funding obligation filings based on NRC guidelines.

Based on the regulatory agreement supported by the PAPUC that dictates Generation's rights and obligations related to the shortfall or excess of trust funds necessary for decommissioning the seven former PECO nuclear units, regardless of whether the funds held in the NDT funds exceed or fall short of the total estimated decommissioning obligation, decommissioning-related activities are generally offset within Exelon's Consolidated Statements of Operations and Comprehensive Income. The offset of decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income results in an equal adjustment to the noncurrent payables to affiliates at Generation and an adjustment to the regulatory liabilities at Exelon. Likewise, PECO has recorded an equal noncurrent affiliate receivable from Generation and a corresponding regulatory liability. Any changes to the PECO regulatory agreements could impact Exelon's and Generation's ability to offset decommissioning-related activities within the Consolidated Statement of Operations and Comprehensive Income, and the impact to Exelon's and Generation's results of operations and financial position could be material.

The decommissioning-related activities related to the Clinton, Oyster Creek and Three Mile Island nuclear plants (the former AmerGen units) and the portions of the Peach Bottom nuclear plants that are not subject to regulatory agreements with respect to the NDT funds are reflected in Exelon's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

Refer to Note 3—Regulatory Matters and Note 22—Related Party Transactions for information regarding regulatory liabilities at ComEd and PECO and intercompany balances between Generation, ComEd and PECO reflecting the obligation to refund to customers any decommissioning-related assets in excess of the related decommissioning obligations.

The following table provides unrealized gains (losses) on NDT funds for 2012, 2011 and 2010:

	For the Years Ended December 31,		
	2012	**2011**	**2010**
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units (a)(b)(c)	$386	$(74)	$294
Net unrealized gains (losses) on decommissioning trust funds—Non-Regulatory Agreement Units (c)	105	(4)	104

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets.
(b) Excludes $73 million and $48 million of net unrealized gains (losses) related to the Zion Station pledged assets in 2012 and 2011. Net unrealized gains (losses) related to Zion Station pledged assets are included in the payable for Zion Station decommissioning on Exelon's Consolidated Balance Sheets.
(c) Net unrealized gains (losses) related to Generation's NDT funds are included within other, net in Exelon's Consolidated Statements of Operations and Comprehensive Income.

Interest and dividends on NDT fund investments are recognized when earned and are included in other, net in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. Interest and dividends earned on the NDT fund investments for the Regulatory Agreement Units, which are subject to regulatory accounting, are eliminated within other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Non-Nuclear Asset Retirement Obligations

Generation has AROs for plant closure costs associated with its fossil and renewable generating facilities, including asbestos abatement, removal of certain storage tanks, restoring leased land to the condition it was in prior to construction of renewable generating stations and other decommissioning-related activities. ComEd, PECO and BGE have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on Exelon's accounting policy for AROs.

The following table provides a rollforward of the non-nuclear AROs reflected on Exelon's Consolidated Balance Sheets from January 1, 2011 to December 31, 2012:

Non-nuclear AROs at January 1, 2011	$223
Net decrease due to changes in, and timing of, estimated future cash flows (a)	(24)
Development projects	7
Accretion expense (b)	9
Payments	(6)
Non-nuclear AROs at December 31, 2011	209
Net increase due to changes in, and timing of, estimated future cash flows (a)	27
Development projects	47
Accretion expense (b)	13
Merger with Constellation (c)	58
Payments	(11)
Non-nuclear AROs at December 31, 2012	$343

(a) During the year ended December 31, 2011, PECO recorded a reduction in operating and maintenance expense of $3 million. Generation and ComEd did not record any reductions in operating and maintenance expense for the year ended December 31, 2011. During the year ended December 31, 2012, Generation recorded a reduction in operating and maintenance expense of $8 million. ComEd and PECO did not record any adjustments in operating and maintenance expense for the year ended December 31, 2012.

(b) For ComEd and PECO, the majority of the accretion is recorded as an increase to a regulatory asset due to the associated regulatory treatment.

(c) Exelon's ARO includes $8 million of BGE costs incurred prior to the closing of Exelon's merger with Constellation. Refer to Note 4—Merger and Acquisitions for additional information.

14. Retirement Benefits

As of December 31, 2012, Exelon sponsored qualified defined benefit pension plans, non-qualified defined benefit pension plans and other postretirement benefit plans for essentially all Generation, ComEd, PECO, BGE and BSC employees. In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's benefit plans and its related assets. Exelon's traditional and cash balance pension plans are intended to be tax-qualified defined benefit plans. Substantially all non-union employees and electing union employees hired on or after January 1, 2001 participate in cash balance pension plans. Effective January 1, 2009, substantially all newly-hired union-represented employees participate in cash balance pension plans. Exelon has elected that the trusts underlying these plans be treated under the IRC as qualified trusts. If certain conditions are met, Exelon can deduct payments made to the qualified trusts, subject to certain IRC limitations.

Benefit Obligations, Plan Assets and Funded Status

Exelon recognizes the overfunded or underfunded status of defined benefit pension and other postretirement benefit plans as an asset or liability on its balance sheet, with offsetting entries to Accumulated Other Comprehensive Income (AOCI) and regulatory assets, in accordance with the applicable authoritative guidance. The measurement date for the plans is December 31. The following table provides a rollforward of the changes in the benefit obligations and plan assets for the most recent two years for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Change in benefit obligation:				
Net benefit obligation at beginning of year	$13,538	$12,524	$4,062	$3,874
Service cost	280	212	156	142
Interest cost	698	649	205	207
Plan participants' contributions	—	—	34	25
Actuarial loss	1,520	807	313	4
Plan amendments	—	—	(103)	—
Acquisitions/divestitures	1,880		362	
Curtailments	(10)	—	(8)	—
Settlements	(169)	—	—	—
Contractual termination benefits	15	—	6	—
Gross benefits paid	(952)	(654)	(219)	(201)
Federal subsidy on benefits paid	—	—	12	11
Net benefit obligation at end of year	$16,800	$13,538	$4,820	$4,062
Change in plan assets:				
Fair value of net plan assets at beginning of year	$11,302	$ 8,859	$1,797	$1,655
Actual return on plan assets	1,484	1,003	197	29
Employer contributions	149	2,094	325	277
Plan participants' contributions	—	—	34	25
Benefits paid [(a)]	(952)	(654)	(218)	(189)
Acquisitions/divestitures	1,543	—	—	—
Settlements	(169)	—	—	—
Fair value of net plan assets at end of year	$13,357	$11,302	$2,135	$1,797

(a) Exelon's other postretirement benefits paid for the years ended December 31, 2012 and 2011 are net of $1.3 million and $12 million, respectively, of reinsurance proceeds received from the Department of Health and Human Services as part of the Early Retiree Reinsurance Program pursuant to the Affordable Care Act of 2010.

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Other current liabilities	$ 15	$ 42	$ 23	$ 2
Pension obligations	3,428	2,194	—	—
Non-pension postretirement benefit obligations	—	—	2,662	2,263
Unfunded status (net benefit obligation less net plan assets)	$3,443	$2,236	$2,685	$2,265

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets. During the fourth quarter of 2012, Exelon completed an optional lump sum election program for select participants in certain of its qualified pension plans, which reduced the obligation and plan assets associated with those plans. This program decreased pension obligations and plan assets by approximately $425 million and $260 million, respectively, resulting in approximately $165 million overall funded status improvement.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO), and fair value of plan assets for all pension plans with a PBO or ABO in excess of plan assets.

	PBO in excess of plan assets	
	2012	2011
Projected benefit obligation	$16,800	$13,538
Fair value of net plan assets	13,357	11,302

	ABO in excess of plan assets	
	2012	2011
Projected benefit obligation	$16,796	$13,538
Accumulated benefit obligation	15,657	12,616
Fair value of net plan assets	13,353	11,302

On a PBO basis, the plans were funded at 80% at December 31, 2012 compared to 83% at December 31, 2011. On an ABO basis, the plans were funded at 85% at December 31, 2012 compared to 90% at December 31, 2011. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2012, 2011 and 2010 for all plans combined. The table reflects an increase in 2012, and a reduction in 2011 and 2010 of net periodic postretirement benefit costs of approximately $(17) million, $28 million and $38 million, respectively, related to a Federal subsidy provided under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Modernization Act), discussed further below.

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Components of net periodic benefit cost:						
Service cost	$ 280	$ 212	$ 190	$ 156	$ 142	$ 124
Interest cost	698	649	660	205	207	214
Expected return on assets	(988)	(939)	(799)	(115)	(111)	(109)
Amortization of:						
Transition obligation	—	—	—	11	9	9
Prior service cost (credit)	15	14	14	(17)	(38)	(56)
Actuarial loss	450	331	254	81	66	74
Curtailment charges	—	—	—	(7)	—	—
Settlement charges	31	—	5	—	—	—
Contractual termination benefits [(a)]	14	—	—	6	—	1
Net periodic benefit cost	$ 500	$ 267	$ 324	$ 320	$ 275	$ 257

(a) ComEd and BGE established regulatory assets of $1 million and $4 million, respectively, for their portion of the contractual termination benefit charge.

Through Exelon's postretirement benefit plans, Exelon provides retirees with prescription drug coverage. The Medicare Modernization Act, enacted on December 8, 2003, introduced a prescription drug benefit under Medicare as well as a Federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to the Medicare prescription drug benefit. Management believes the prescription drug benefit provided under Exelon's postretirement benefit plans meets the requirements for the subsidy. See the *Health Care Reform Legislation* section below for further discussion regarding the income tax treatment of Federal subsidies of prescription drug benefits.

The effect of the subsidy on the components of net periodic postretirement benefit cost for the years ended December 31, 2012, 2011 and 2010 included in the consolidated financial statements was as follows:

	2012	2011	2010
Amortization of the actuarial experience loss	$(17)	$ 3	$ 9
Reduction in current period service cost	—	9	10
Reduction in interest cost on the APBO	—	16	19
Total effect of subsidy on net periodic postretirement benefit cost	$(17)	$28	$38

Components of AOCI and Regulatory Assets

Under the authoritative guidance for regulatory accounting, a portion of current year actuarial gains and losses and prior service costs (credits) is capitalized within Exelon's Consolidated Balance Sheets to reflect the expected regulatory recovery of these amounts, which would otherwise be recorded to AOCI. The following tables provide the components of AOCI and regulatory assets for the years ended December 31, 2012, 2011 and 2010 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets:						
Current year actuarial (gain) loss	$1,693	$ 744	$ 737	$ 304	$ 74	$—
Amortization of actuarial gain (loss)	(450)	(331)	(254)	(81)	(66)	(74)
Current year prior service (credit) cost	1	—	—	(109)	—	—
Amortization of prior service (cost) credit	(15)	(14)	(14)	17	38	56
Current year transition (asset) obligation	—			1		
Amortization of transition asset (obligation)	—	—	—	(11)	(9)	(9)
Curtailments	(10)	—	—	(1)	—	—
Settlements	(31)	—	(5)	—	—	—
Total recognized in AOCI and regulatory assets (a)	$1,188	$ 399	$ 464	$ 120	$ 37	$(27)

(a) Of the $1,188 million related to pension benefits, $283 million and $904 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $120 million related to other postretirement benefits, $39 million and $81 million were recognized in AOCI and regulatory assets, respectively, during 2012. Of the $399 million related to pension benefits, $181 million and $218 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $37 million related to other postretirement benefits, $13 million and $24 million were recognized in AOCI and regulatory assets, respectively, during 2011. Of the $464 million related to pension benefits, $310 million and $154 million were recognized in AOCI and regulatory assets, respectively, during 2010. Of the $(27) million related to other postretirement benefits, $(9) million and $(18) million were recognized in AOCI and regulatory assets, respectively, during 2010.

The following table provides the components of Exelon's gross accumulated other comprehensive loss and regulatory assets that have not been recognized as components of periodic benefit cost at December 31, 2012 and 2011, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Transition obligation	$ —	$ —	$ —	$ 11
Prior service cost (credit)	76	90	(107)	(16)
Actuarial loss	7,931	6,729	1,185	963
Total (a)	$8,007	$6,819	$1,078	$958

(a) Of the $8,007 million related to pension benefits, $4,594 million and $3,413 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $1,078 million related to other postretirement benefits, $514 million and $564 million are included in AOCI and regulatory assets, respectively, at December 31, 2012. Of the $6,819 million related to pension benefits, $4,311 million and $2,508 million are included in AOCI and regulatory assets, respectively, at December 31, 2011. Of the $958 million related to other postretirement benefits, $475 million and $483 million are included in AOCI and regulatory assets, respectively, at December 31, 2011.

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2012 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2013. These estimates are subject to the completion of an actuarial valuation of Exelon's pension and other postretirement benefit obligations, which will reflect actual census data as of January 1, 2013 and actual claims activity as of December 31, 2012. The valuation is expected to be completed in the first quarter of 2013 for legacy Exelon plans and in the second quarter of 2013 for legacy Constellation plans.

	Pension Benefits	Other Postretirement Benefits
Prior service cost (credit)	$ 14	$(19)
Actuarial loss	568	84
Total [(a)]	$582	$ 65

(a) Of the $582 million related to pension benefits at December 31, 2012, $315 million and $267 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively. Of the $65 million related to other postretirement benefits at December 31, 2012, $29 million and $36 million are expected to be amortized from AOCI and regulatory assets in 2013, respectively.

Assumptions

The measurement of the plan obligations and costs of providing benefits under Exelon's defined benefit and other postretirement plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, Exelon considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Exelon's expected level of contributions to the plans, the long-term expected investment rate credited to employees participating in cash balance plans and the anticipated rate of increase of health care costs. Additionally, assumptions related to plan participants include the incidence of mortality, the expected remaining service period, the level of compensation and rate of compensation increases, employee age and length of service, among other factors.

Expected Rate of Return. In selecting the expected rate of return on plan assets, Exelon considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by Exelon's target asset class allocations.

The following assumptions were used to determine the benefit obligations for all of the plans at December 31, 2012, 2011 and 2010. Assumptions used to determine year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Discount rate	3.92%	4.74%	5.26%	4.00%	4.80%	5.30%
Rate of compensation increase	(a)	3.75%	3.75%	(a)	3.75%	3.75%
Mortality table	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2013 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.50% decreasing to ultimate trend of 5.00% in 2017	6.50% decreasing to ultimate trend of 5.00% in 2017	7.00% decreasing to ultimate trend of 5.00% in 2015

(a) 3.25% for 2013-2017 and 3.75% thereafter.

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2012, 2011 and 2010:

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	2012	2011	2010
Discount rate	3.71%(a)	5.26%	5.83%	3.72%(a)	5.30%	5.83%
Expected return on plan assets	7.50%(b)	8.00%(b)	8.50%(b)	6.68%(b)	7.08%(b)	7.83%(b)
Rate of compensation increase	3.75%	3.75%	4.00%	3.75%	3.75%	4.00%
Mortality table	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2012 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	6.50% decreasing to ultimate trend of 5.00% in 2017	7.00% decreasing to ultimate trend of 5.00% in 2015	7.50% decreasing to ultimate trend of 5.00% in 2015

(a) The initial discount rates used to establish Exelon's pension and other postretirement benefits costs for 2012 were 4.74% and 4.80%, respectively. Certain of the benefit plans were remeasured during the year due to the Constellation merger, plan settlement and curtailment events, and plan changes using discount rates within the indicated ranges. 2012 costs reflect the impact of these remeasurements.

(b) Not applicable to pension and other postretirement benefit plans that do not have plan assets.

Assumed health care cost trend rates have a significant effect on the costs reported for the other postretirement benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

Effect of a one percentage point increase in assumed health care cost trend:	
on 2012 total service and interest cost components	$ 81
on postretirement benefit obligation at December 31, 2012	845
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2012 total service and interest cost components	(56)
on postretirement benefit obligation at December 31, 2012	(569)

Health Care Reform Legislation

In March 2010, the Health Care Reform Acts were signed into law, which contain a number of provisions that impact retiree health care plans provided by employers. One such provision reduces the deductibility, for Federal income tax purposes, of retiree health care costs to the extent an employer's postretirement health care plan receives Federal subsidies that provide retiree prescription drug benefits at least equivalent to those offered by Medicare. Although this change did not take effect immediately, Exelon was required to recognize the full accounting impact in its financial statements in the period in which the legislation was enacted. As a result, in the first quarter of 2010, Exelon recorded total after-tax charges of approximately $65 million to income tax expense to reverse deferred tax assets previously established. Generation, ComEd, PECO and BGE recorded charges of $24 million, $11 million, $9 million and $3 million, respectively. Additionally, as a result of this deductibility change for employers and other Health Care Reform provisions that impact the federal prescription drug subsidy options provided to employers, Exelon has made a change in the manner in which it will receive prescription drug subsidies beginning in 2013.

Additionally, the Health Care Reform Acts also include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. Although the excise tax does not go into effect until 2018, accounting guidance requires Exelon to incorporate the estimated impact of the excise tax in its annual actuarial valuation. The application of the legislation is still unclear and Exelon continues to monitor the Department of Labor and IRS for additional guidance. Certain key assumptions are required to estimate the impact of the excise tax on Exelon's other postretirement benefit obligation, including projected inflation rates (based on the CPI) and whether pre- and post-65 retiree populations can be aggregated in determining the premium values of health care benefits. Exelon reflected its best estimate of the expected impact in its annual actuarial valuation.

Contributions

The following table provides contributions made by Exelon to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2012	**2011**	**2010**	**2012 (a)**	**2011 (a)**	**2010 (a)**
Exelon	$149	$2,094	$766	$323	$277	$203

(a) Exelon presents the cash contributions above net of Federal subsidy payments received on its Consolidated Statements of Cash Flows. Exelon received Federal subsidy payments of $10 million in 2012, $11 million in 2011, and $10 million in 2010.

Exelon plans to contribute approximately $255 million to its qualified pension plans in 2013. Exelon plans to make non-qualified pension plan benefit payments of approximately $15 million in 2013. Management considers various factors when making pension funding decisions, including actuarially determined minimum contribution requirements under ERISA, contributions required to avoid benefit restrictions and at-risk status as defined by the Pension Protection Act of 2006 (the Act), management of the pension obligation and regulatory implications. The Act requires the attainment of certain funding levels to avoid benefit restrictions (such as an inability to pay lump sums or to accrue benefits prospectively), and at-risk status (which triggers higher minimum contribution requirements and participant notification). Additionally, for Exelon's largest qualified pension plan, the projected contributions reflect a funding strategy of contributing the greater of $250 million, which approximates service cost, or the minimum amounts under ERISA to avoid benefit restrictions and at-risk status. This level funding strategy helps minimize volatility of future period required pension contributions. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower minimum pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law will be applied in 2012 while others take effect in 2013. The estimated impacts of the law are reflected in the projected pension contributions.

Unlike the qualified pension plans, Exelon's other postretirement plans are not subject to regulatory minimum contribution requirements. Management considers several factors in determining the level of contributions to Exelon's other postretirement benefit plans, including levels of benefit claims paid and regulatory implications (amounts deemed prudent to meet regulatory expectations and best assure continued rate recovery). Exelon expects to contribute approximately $292 million to the other postretirement benefit plans in 2013.

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2012 were:

	Pension Benefits	**Other Postretirement Benefits**
2013	$ 943	$ 197
2014	807	204
2015	891	212
2016	868	220
2017	902	231
2018 through 2022	5,161	1,330
Total estimated future benefit payments through 2022	$9,572	$2,394

Plan Assets

Investment Strategy. On a regular basis, Exelon evaluates its investment strategy to ensure that plan assets will be sufficient to pay plan benefits when due. As part of this ongoing evaluation, Exelon may make changes to its targeted asset allocation and investment strategy.

Exelon has developed and implemented an investment strategy for its qualified pension plans that has reduced the volatility of its pension assets relative to its pension liabilities. Exelon is likely to continue to gradually increase the liability hedging portfolio as the funded status of its plans improves. The overall objective is to achieve attractive risk-adjusted returns that will balance the liquidity requirements of the plans' liabilities while striving to minimize the risk of significant losses. This investment strategy would tend to result in a lower expected rate of return on plan assets in future years. Trust assets for Exelon's other postretirement plans are managed in a diversified investment strategy that prioritizes maximizing liquidity and returns while minimizing asset volatility.

Exelon used an EROA of 7.50% and 6.45% to estimate its 2013 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2012 and 2011 asset allocations were as follows:

Pension Plans

		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2012**	**2011**
Equity securities	34%	35%	32%
Fixed income securities	40%	40	47
Alternative investments [(a)]	26%	25	21
Total		100%	100%

Other Postretirement Benefit Plans

		Percentage of Plan Assets at December 31,	
Asset Category	**Target Allocation**	**2012**	**2011**
Equity securities	45%	46%	37%
Fixed income securities	40%	40	53
Alternative investments [(a)]	15%	14	10
Total		100%	100%

(a) Alternative investments include private equity, hedge funds and real estate.

Concentrations of Credit Risk. Exelon evaluated its pension and other postretirement benefit plans' asset portfolios for the existence of significant concentrations of credit risk as of December 31, 2012. Types of concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, type of industry, foreign country, and individual fund. As of December 31, 2012, there were no significant concentrations (defined as greater than 10 percent of plan assets) of risk in Exelon's pension and other postretirement benefit plan assets.

Fair Value Measurements

The following table presents Exelon's pension and other postretirement benefit plan assets measured and recorded at fair value on Exelon's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy at December 31, 2012 and 2011:

At December 31, 2012 [(a)]	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 1	$ —	$ —	$ 1
Equity securities:				
Individually held	2,562	—	—	2,562
Commingled funds	—	1,111	—	1,111
Mutual funds [(c)]	323	—	—	323
Equity securities subtotal	2,885	1,111	—	3,996
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,037	—	—	1,037
Debt securities issued by states of the United States and by political subdivisions of the states	—	108	—	108
Foreign debt securities	—	252	—	252
Corporate debt securities	—	3,330	—	3,330
Federal agency mortgage-backed securities	—	117	—	117
Non-Federal agency mortgage-backed securities	—	28	—	28
Commingled funds	—	274	—	274
Mutual funds [(c)]	4	291	—	295
Derivative instruments [(b)]:				
Assets	—	9	—	9
Liabilities	—	(21)	—	(21)
Fixed income securities subtotal	1,041	4,388	—	5,429
Private equity	—	—	754	754
Hedge funds	—	1,080	1,235	2,315
Real estate:				
Individually held	280	—	—	280
Commingled funds	—	75	—	75
Real estate funds	—	—	426	426
Real estate subtotal	280	75	426	781
Pension plan assets subtotal	4,207	6,654	2,415	13,276

At December 31, 2012 [(a)]	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	44	—	—	44
Equity securities:				
Individually held	198	—	—	198
Commingled funds	—	530	—	530
Mutual funds [(c)]	230	—	—	230
Equity securities subtotal	428	530	—	958
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	18	—	—	18
Debt securities issued by states of the United States and by political subdivisions of the states	—	125	—	125
Foreign debt securities	—	3	—	3
Corporate debt securities	—	50	—	50
Federal agency mortgage-backed securities	—	52	—	52
Non-Federal agency mortgage-backed securities	—	6	—	6
Commingled funds	—	271	—	271
Mutual funds [(c)]	295	2	—	297
Fixed income securities subtotal	313	509	—	822
Private equity	—	—	1	1
Hedge funds	—	188	12	200
Real estate:				
Individually held	7	—	—	7
Commingled funds	—	2	—	2
Real estate funds	—	6	95	101
Real estate subtotal	7	8	95	110
Other postretirement benefit plan assets subtotal	792	1,235	108	2,135
Total pension and other postretirement benefit plan assets [(d)(e)]	$4,999	$7,889	$2,523	$15,411

At December 31, 2011 (a)	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 8	$ —	$ —	$ 8
Equity securities:				
Individually held	1,985	—	—	1,985
Commingled funds	—	858	—	858
Mutual funds	—	389	—	389
Equity securities subtotal	1,985	1,247	—	3,232
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,616	48	—	1,664
Debt securities issued by states of the United States and by political subdivisions of the states	—	88	—	88
Foreign debt securities	—	224	—	224
Corporate debt securities	—	2,561	—	2,561
Federal agency mortgage-backed securities	—	156	—	156
Non-Federal agency mortgage-backed securities	—	28	—	28
Commingled funds	—	202	—	202
Mutual funds	—	277	—	277
Fixed income securities subtotal	1,616	3,584	—	5,200
Private equity	—	—	672	672
Hedge funds (f)	—	—	1,525	1,525
Real estate:				
Individually held	207	—	—	207
Commingled funds	—	125	—	125
Real estate funds	—	—	229	229
Real estate subtotal	207	125	229	561
Pension plan assets subtotal	3,816	4,956	2,426	11,198
Other postretirement benefit plan assets				
Cash equivalents	73	—	—	73
Equity securities:				
Individually held	110	—	—	110
Commingled funds	—	415	—	415
Mutual funds	—	171	—	171
Equity securities subtotal	110	586	—	696
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	26	3	—	29
Debt securities issued by states of the United States and by political subdivisions of the states	—	93	—	93
Foreign debt securities	—	4	—	4
Corporate debt securities	—	41	—	41
Federal agency mortgage-backed securities	—	34	—	34
Non-Federal agency mortgage-backed securities	—	7	—	7
Commingled funds	—	385	—	385
Mutual funds	—	256	—	256
Fixed income securities subtotal	26	823	—	849
Private equity	—	—	1	1
Hedge funds (f)	—	—	157	157
Real estate				
Individually held	4	—	—	4
Commingled funds	—	1	—	1
Real Estate funds	—	—	7	7
Real estate subtotal	4	1	7	12
Other postretirement benefit plan assets subtotal	213	1,410	165	1,788
Total pension and other postretirement benefit plan assets (d)	$4,029	$6,366	$2,591	$12,986

(a) See Note 9—Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) Derivative instruments have a total notional amount of $2,498 million and $910 million at December 31, 2012 and 2011, respectively. The notional principal amounts for these instruments provide one measure of the transaction volume outstanding as of the fiscal years ended and do not represent the amount of the company's exposure to credit or market loss.
(c) In 2012, Exelon reassessed its policy over the criteria that mutual fund investments must meet in order to be categorized within Level 1 of the fair value hierarchy. Therefore, certain mutual fund investments that were categorized within Level 2 in prior periods have been re-categorized as Level 1 investments as of December 31, 2012. The re-categorization of these mutual fund investments resulted in a transfer out of Level 2 of $852 million.
(d) Excludes net assets of $77 million and $43 million at December 31, 2012 and 2011 respectively; which are required to reconcile to the fair value of net plan assets. These items consist primarily of receivables related to pending securities sales, interest and dividends receivable, and payables related to pending securities purchases.
(e) Includes fixed income commingled fund assets of $66 million as of December 31, 2012. The fair value of these fixed income commingled fund assets of $69 million, as of December 31, 2011, are excluded from the tables above.
(f) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.

The following table presents the reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2012 and 2011:

	Hedge funds	Private equity	Real estate	Total
Pension Assets				
Balance as of January 1, 2012	$1,525	$ 672	$229	$2,426
Actual return on plan assets:				
Relating to assets still held at the reporting date	138	55	24	217
Purchases, sales and settlements:				
Purchases	447	108	134	689
Sales	(6)	—	—	(6)
Settlements	(4)	(128)	(28)	(160)
Transfers into (out of) Level 3 [(a)(b)(c)]	(865)	47	67	(751)
Balance as of December 31, 2012	$1,235	$ 754	$426	$2,415
Other Postretirement Benefits				
Balance as of January 1, 2012	$ 157	$ 1	$ 7	$ 165
Actual return on plan assets:				
Relating to assets still held at the reporting date	11	—	3	14
Purchases, sales and settlements:				
Purchases	32	—	91	123
Sales	—	—	—	—
Settlements	—	—	(1)	(1)
Transfers into (out of) Level 3 [(a)(b)(c)]	(188)	—	(5)	(193)
Balance as of December 31, 2012	$ 12	$ 1	$ 95	$ 108

	Hedge funds	Private equity	Real estate	Total
Pension Assets				
Balance as of January 1, 2011	$ 329	$ 536	$179	$1,044
Actual return on plan assets [(d)]:				
Relating to assets still held at the reporting date	(26)	84	46	104
Purchases, sales and settlements [(d)]:				
Purchases	1,222	121	13	1,356
Sales	—	—	—	—
Settlements	—	(69)	(9)	(78)
Transfers into (out of) Level 3	—	—	—	—
Balance as of December 31, 2011	$1,525	$ 672	$229	$2,426
Other Postretirement Benefits				
Balance as of January 1, 2011	$ 5	$ —	$ 8	$ 13
Actual return on plan assets:				
Relating to assets still held at the reporting date	(3)	—	(1)	(4)
Purchases, sales and settlements:				
Purchases	155	1	—	156
Sales	—	—	—	—
Settlements	—	—	—	—
Transfers into (out of) Level 3	—	—	—	—
Balance as of December 31, 2011	$ 157	$ 1	$ 7	$ 165

(a) In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's pension plan assets resulting in transfers into Level 3 of $141 million.

(b) In 2012, Exelon refined its policy over the criteria that hedge fund investments must meet in order to be categorized within Level 2 and Level 3 of the fair value hierarchy. Therefore, certain hedge fund investments that were categorized within Level 3 in prior periods have been re-categorized as Level 2 investments as of December 31, 2012. The re-categorization of these hedge fund investments is reflected as transfers out of Level 3 of $1.1 billion.

(c) In 2012, the liquidity terms of a certain real estate investment changed to allow redemption within a reasonable period of time from the redemption date which led to a transfer out of Level 3 to Level 2 of $5 million.

(d) Certain prior year amounts have been reclassified for comparative purposes.

Valuation Techniques Used to Determine Fair Value

Cash equivalents. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities and money market funds, are considered cash equivalents. The fair values are based on observable market prices and, therefore, are included in the recurring fair value measurements hierarchy as Level 1.

Equity securities. With respect to individually held equity securities, including investments in U.S. and international securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Exelon is able to independently corroborate. Equity securities held individually are primarily traded on exchanges that contain only actively traded securities, due to the volume trading requirements imposed by these exchanges. Equity securities are valued based on quoted prices in active markets and are categorized as Level 1.

Equity commingled funds and mutual funds are maintained by investment companies that hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For equity commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Fixed income. For fixed income securities, which consist primarily of corporate debt securities, foreign government securities, municipal bonds, asset and mortgage-backed securities, mutual funds and derivative instruments, the trustees obtain multiple prices from pricing vendors whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable.

Exelon has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Exelon selectively corroborates the fair values of securities by comparison to other market-based price sources. Investments in U.S. Treasury securities have been categorized as Level 1 because they trade in highly-liquid and transparent markets. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences and are categorized as Level 2.

Derivative instruments consisting primarily of interest rate swaps to manage risk are recorded at fair value. Derivative instruments are valued based on external price data of comparable securities and have been categorized as Level 2.

Fixed income commingled funds and mutual funds, including short-term investment funds, are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. The values of some of these funds are publicly quoted. For mutual funds which are publicly quoted, the funds are valued based on quoted prices in active markets and have been categorized as Level 1. For fixed income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2.

Private equity. Private equity investments include those in limited partnerships that invest in operating companies that are not publicly traded on a stock exchange such as leveraged buyouts, growth capital, venture capital, distressed investments and investments in natural resources. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments, which include inputs such as cost, operating results, discounted future cash flows and market based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3.

Hedge funds. Hedge fund investments include those seeking to maximize absolute returns using a broad range of strategies to enhance returns and provide additional diversification. The fair value of hedge funds is determined using NAV or ownership interest of the investments. Exelon has the ability to redeem these investments at NAV or its equivalent subject to certain restrictions which may include a lock-up period or a gate. For Exelon's investments that have terms that allow redemption within a reasonable period of time from the measurement date, the hedge fund investments are categorized as Level 2. For investments that have restrictions that may limit Exelon's ability to redeem the investments at the measurement date or within a reasonable period of time, the hedge fund investments are categorized as Level 3.

Real estate. Real estate investment trusts valued daily based on quoted prices in active markets are categorized as Level 1. Real estate commingled funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon's overall investment strategy. Since these funds are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Other real estate funds are funds with a direct investment in a pool of real estate properties. These funds are valued by investment managers on a periodic basis using pricing models that use independent appraisals from sources with professional qualifications. Since these valuation inputs are not highly observable, these real estate funds have been categorized as Level 3.

Defined Contribution Savings Plan

Exelon, Generation, ComEd, PECO and BGE participate in a 401(k) defined contribution savings plan sponsored by Exelon. The plan is qualified under applicable sections of the IRC and allows employees to contribute a portion of their pre-tax income in accordance with specified guidelines. Exelon, Generation, ComEd, PECO and BGE match a percentage of the employee contribution up to certain limits. The following table presents matching contributions to the savings plan for the years ended December 31, 2012, 2011 and 2010:

For the Year Ended December 31,	
2012	$67
2011	78
2010	81

15. Plant Retirements

Schuylkill Station and Riverside Station

On October 31, 2012, Generation notified PJM of its intention to permanently retire Schuylkill Generating Station Unit 1 by February 1, 2013, and Riverside Generating Station Unit 6 by June 1, 2014. Schuylkill Unit 1 is a 166 MW peaking oil unit located in Philadelphia, Pennsylvania, which was placed in service in 1958. Riverside Unit 6 is a 115 MW peaking gas/kerosene unit located in Baltimore, Maryland, which was placed in service in 1970. The units are being retired because they are no longer economic to operate due to their age, relatively high capital and operating costs and declining revenue expectations. On November 30, 2012, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Schuylkill Unit 1 retirement date and as a result, Schuylkill Unit 1 was retired on January 1, 2013. On January 7, 2013, PJM notified Generation that it did not identify any transmission system reliability issues associated with the proposed Riverside Unit 6 retirement date. Exelon will determine the final retirement date for Riverside Unit 6 during the second quarter of 2013. The early retirements will not have a material impact on Generation or Exelon's results of operations, cash flows or financial position.

Oyster Creek

On December 8, 2010, in connection with the executed Administrative Consent Order (ACO) with the NJDEP, Exelon announced that Generation will permanently cease generation operations at Oyster Creek by December 31, 2019.

Eddystone Station and Cromby Station

In 2009, Exelon announced its intention to permanently retire three coal-fired generating units and one oil/gas-fired generating unit, effective May 31, 2011, in response to the economic outlook related to the continued operation of these four units. However, PJM determined that transmission reliability upgrades would be necessary to alleviate reliability impacts and that those upgrades would be completed in a manner that will permit Generation's retirement of two of the units on that date and two of the units subsequent to May 31, 2011. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; Cromby Unit 2 retired on December 31, 2011 and Eddystone Unit 2 retired on May 31, 2012. On May 27, 2011, the FERC approved a settlement providing for a reliability-must-run rate schedule, which defines compensation to be paid to Generation for continuing to operate these units. The monthly fixed-cost recovery during the reliability-must-run period for Eddystone Unit 2 is approximately $6 million. Such revenue is intended to recover total expected operating costs, plus a return on net assets, of the two units during the reliability-must-run period. In addition, Generation is reimbursed for variable costs, including fuel, emissions costs, chemicals, auxiliary power and for project investment costs during the reliability-must-run period. Eddystone Unit 2 and Cromby Unit 2 operated under the reliability-must-run agreement from June 1, 2011 until their respective retirement dates.

Since the announced retirements in December 2009, Generation recorded pre-tax expense of $44 million, which included $18 million of expense for the write down of inventory, $13 million of expense for estimated salary continuance and health and welfare severance benefits and $13 million of shut down costs recorded within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the year ended December 31, 2012, Generation recorded $1 million of expense for the write down of inventory and $11 million of shut down costs. During the year ended December 31, 2011, Generation recorded pre-tax expense of $4 million for estimated salary continuance and health and welfare severance benefits and $2 million of shut down costs.

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from January 1, 2011 through December 31, 2012:

Severance Benefits Obligation	
Balance at January 1, 2011	$ 7
Severance charges recorded	4
Cash payments	(4)
Balance at December 31, 2011	7
Cash payments	(4)
Balance at December 31, 2012	$ 3

16. Preferred and Preference Securities

At December 31, 2012 and 2011, Exelon was authorized to issue up to 100,000,000 shares of preferred securities, none of which were outstanding.

Preferred and Preference Securities of Subsidiaries

At December 31, 2012 and 2011, ComEd prior preferred securities and ComEd cumulative preference securities consisted of 850,000 shares and 6,810,451 shares authorized, respectively, none of which were outstanding.

At December 31, 2012 and 2011, PECO cumulative preferred securities, no par value, consisted of 15,000,000 shares authorized and the outstanding amounts set forth below. Shares of preferred securities have full voting rights, including the right to cumulate votes in the election of directors.

		December 31,			
	Redemption Price [(a)]	2012	2011	2012	2011
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
$4.68 (Series D)	$104.00	150,000	150,000	$15	$15
$4.40 (Series C)	112.50	274,720	274,720	27	27
$4.30 (Series B)	102.00	150,000	150,000	15	15
$3.80 (Series A)	106.00	300,000	300,000	30	30
Total preferred securities		874,720	874,720	$87	$87

(a) Redeemable, at the option of PECO, at the indicated dollar amounts per share, plus accrued dividends.

At December 31, 2012 and 2011, BGE cumulative preference stock, $100 par value, consisted of 6,500,000 shares authorized and the outstanding amounts set forth below. Shares of BGE preference stock have no voting power except for the following:

- The preference stock has one vote per share on any charter amendment which would create or authorize any shares of stock ranking prior to or on a parity with the preference stock as to either dividends or distribution of assets, or which would substantially adversely affect the contract rights, as expressly set forth in BGE's charter, of the preference stock, each of which requires the affirmative vote of two-thirds of all the shares of preference stock outstanding; and
- Whenever BGE fails to pay full dividends on the preference stock and such failure continues for one year, the preference stock shall have one vote per share on all matters, until and unless such dividends shall have been paid in full. Upon liquidation, the holders of the preference stock of each series outstanding are entitled to receive the par amount of their shares and an amount equal to the unpaid accrued dividends.

		December 31,			
	Redemption Price [(a)]	2012	2011	2012	2011
		Shares Outstanding		Dollar Amount	
Series (without mandatory redemption)					
7.125%, 1993 Series	$100.36	400,000	400,000	$ 40	$ 40
6.97%, 1993 Series	100.35	500,000	500,000	50	50
6.70%, 1993 Series	100.67	400,000	400,000	40	40
6.99%, 1995 Series	101.05	600,000	600,000	60	60
Total preference stock		1,900,000	1,900,000	$190	$190

(a) Redeemable, at the option of BGE, at the indicated dollar amounts per share, plus accrued and unpaid dividends.

17. Common Stock

At December 31, 2012 and 2011, Exelon's common stock without par value consisted of 2,000,000,000 shares authorized and 854,781,389 shares and 663,368,958, shares outstanding, respectively. At December 31, 2012 and 2011, ComEd's common stock with a $ 12.50 par value consisted of 250,000,000 shares authorized and 127,016,761 shares and 127,016,529 shares outstanding, respectively. At December 31, 2012 and 2011, PECO's common stock without par value consisted of 500,000,000 shares authorized and 170,478,507 shares outstanding. At December 31, 2012 and 2011, BGE's common stock without par value consisted of 175,000,000 shares authorized and 1,000 shares outstanding.

ComEd had 74,182 and 75,096 warrants outstanding to purchase ComEd common stock at December 31, 2012 and 2011, respectively. The warrants entitle the holders to convert such warrants into common stock of ComEd at a conversion rate of one share of common stock for three warrants. At December 31, 2012 and 2011, 24,727 and 25,032 shares of common stock, respectively, were reserved for the conversion of warrants.

Share Repurchases

Share Repurchase Programs. In April 2004, Exelon's Board of Directors approved a discretionary share repurchase program that allowed Exelon to repurchase shares of its common stock on a periodic basis in the open market. The share repurchase program was intended to mitigate, in part, the dilutive effect of shares issued under Exelon's employee stock option plan and Exelon's ESPP. The aggregate value of the shares of common stock repurchased pursuant to the program cannot exceed the economic benefit received after January 1, 2004 due to stock option exercises and share purchases pursuant to Exelon's ESPP. The economic benefit consists of the direct cash proceeds from purchases of stock and the tax benefits associated with exercises of stock options. The 2004 share repurchase program had no specified limit on the number of shares that could be repurchased and no specified termination date. Any shares repurchased are held as treasury shares, at cost, unless cancelled or reissued at the discretion of Exelon's management.

In the third quarter of 2008, Exelon's Board of Directors approved a share repurchase program for $1.5 billion of its common stock. Subsequently, Exelon's management determined to defer indefinitely any share repurchases. This decision was made in light of a variety of factors, including: developments affecting the world economy and commodity markets, including those for electricity and gas; the continued uncertainty in capital and credit markets and the potential impact of those events on Exelon's future cash needs; projected cash needs to support investment in the business, including maintenance capital and nuclear uprates; and value-added growth opportunities.

Under the share repurchase programs dating back to 2004, 34.7 million shares of common stock are held as treasury stock with a cost of $2.3 billion at December 31, 2012. During 2012, 2011 and 2010, Exelon had no common stock repurchases.

Stock-Based Compensation Plans

Exelon grants stock-based awards through its LTIP, which primarily includes performance share awards, stock options and restricted stock units. At December 31, 2012, there were approximately 20 million shares authorized for issuance under the LTIP. For the years ended December 31, 2012, 2011 and 2010, exercised and distributed stock-based awards were primarily issued from authorized but unissued common stock shares.

As the LTIP sponsor, Exelon is the sole issuer of all stock-based compensation awards. All awards are recorded as equity or a liability in Exelon's Consolidated Balance Sheets. The stock-based compensation expense specifically attributable to the employees of Generation, ComEd, PECO and BGE is directly recorded to operating and maintenance expense within each of their respective Consolidated Statements of Operations. Stock-based compensation expense attributable to BSC employees is allocated to the Registrants using a cost-causative allocation method.

In connection with the acquisition of Constellation in March 2012, Exelon assumed Constellation's 1995 Long-Term Incentive Plan, 2002 Senior Management Long-Term Incentive Plan, Amended and Restated 2007 Long-Term Incentive Plan, Amended and Restated Management Long-Term Incentive Plan and Executive Long-Term Incentive Plan (collectively and as amended, if applicable, the "Constellation Plans"). Stock-based awards granted under the Constellation Plans and held by Constellation employees were generally converted into outstanding Exelon stock-based compensation awards with the estimated fair value determined to be $71 million using the Black-Scholes model. Refer to Note 4 - Merger and Acquisitions for further information regarding the merger transaction. Specifically, as of the merger closing: (1) Exelon converted 12,037,093 outstanding shares that were subject to Constellation stock options into 11,194,151 Exelon stock options valued at $65 million; and (2) Exelon converted 165,219 Constellation no-sale restricted stock units into 153,654 Exelon no-sale restricted stock units valued at $6 million.

Exelon generally grants most of its stock options in the first quarter of each year. In connection with the merger with Constellation, the Compensation Committee of Exelon's Board of Directors elected to delay the annual equity award grant from January 2012 to the effective date of the merger on March 12, 2012, in order to ensure that a majority of eligible employees receive grants on the same date and at the same market price.

The following table presents the stock-based compensation expense included in Exelon's Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010:

Components of Stock-Based Compensation Expense	Year Ended December 31, 2012	2011	2010
Performance share awards	$ 46	$ 26	$ 6
Stock options	15	8	10
Restricted stock units	50	31	21
Other stock-based awards	4	4	4
Total stock-based compensation expense included in operating and maintenance expense	115	69	41
Income tax benefit	(44)	(27)	(16)
Total after-tax stock-based compensation expense	$ 71	$ 42	$ 25

There were no significant stock-based compensation costs capitalized during the years ended December 31, 2012, 2011 and 2010.

Exelon receives a tax deduction based on the intrinsic value of the award on the exercise date for stock options and distribution date for performance share awards and restricted stock units. For each award, throughout the requisite service period, Exelon recognizes the tax benefit related to compensation costs. The tax deductions in excess of the benefits recorded throughout the requisite service period are recorded to common stock and are included in other financing activities within Exelon's Consolidated Statements of Cash Flows. The following table presents information regarding Exelon's tax benefits for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31, 2012	2011	2010
Realized tax benefit when exercised/distributed:			
Stock options	$ 3	$2	$ 5
Restricted stock units	11	8	9
Performance share awards	7	7	13
Stock deferral plan	—	1	1
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	$ 2	$1	$ 3

Stock Options

Non-qualified stock options to purchase shares of Exelon's common stock are granted under the LTIP. The exercise price of the stock options is equal to the fair market value of the underlying stock on the date of option grant. Stock options granted under the LTIP generally become exercisable upon a specified vesting date. The vesting period of stock options is generally four years. All stock options expire ten years from the date of grant.

The value of stock options at the date of grant is expensed over the requisite service period using the straight-line method. The requisite service period for stock options is generally four years. However, certain stock options become fully vested upon the employee reaching retirement-eligibility. The value of the stock options granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility.

Exelon grants most of its stock options in the first quarter of each year. Stock options granted during the remaining quarters of 2012, 2011 and 2010 were not significant.

The fair value of each option is estimated on the date of grant using the Black-Scholes-Merton option-pricing model. The following table presents the weighted average assumptions used in the pricing model for grants and the resulting weighted average grant date fair value of stock options granted for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Dividend yield	5.28%	4.84%	4.56%
Expected volatility	23.20%	24.40%	27.10%
Risk-free interest rate	1.30%	2.65%	2.96%
Expected life (years)	6.25	6.25	6.25
Weighted average grant date fair value (per share)	$ 4.18	$ 6.22	$ 8.08

The assumptions above relate to Exelon stock options granted during the period and therefore do not include stock options that were converted in connection with the merger with Constellation during the year ended December 31, 2012.

The dividend yield is based on several factors, including Exelon's most recent dividend payment at the grant date and the average stock price over the previous year. Expected volatility is based on implied volatilities of traded stock options in Exelon's common stock and historical volatility over the estimated expected life of the stock options. The risk-free interest rate for a security with a term equal to the expected life is based on a yield curve constructed from U.S. Treasury strips at the time of grant. For each year presented, the expected life represents the period of time the stock options are expected to be outstanding and is based on the simplified method. Exelon believes that the simplified method is appropriate due to several factors that result in historical exercise data not being sufficient to determine a reasonable estimate of expected term. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table presents information with respect to stock option activity for the year ended December 31, 2012:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2011	11,553,761	$48.49		
Options granted	2,372,000	39.66		
Converted Constellation options	11,194,151	41.35		
Options exercised	(1,776,041)	26.41		
Options forfeited	(980,986)	42.90		
Options expired	(459,104)	49.45		
Balance of shares outstanding at December 31, 2012	21,903,781	$45.91	5.58	$13
Exercisable at December 31, 2012 (a)	19,943,116	$46.40	5.25	$13

(a) Includes stock options issued to retirement eligible employees.

The following table summarizes additional information regarding stock options exercised for the years ended December 31, 2012, 2011 and 2010:

	Year Ended December 31,		
	2012	2011	2010
Intrinsic value (a)	$19	$ 5	$13
Cash received for exercise price	47	13	24

(a) The difference between the market value on the date of exercise and the option exercise price.

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2012:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2011 [a]	877,050	$48.66
Granted [b]	2,372,000	39.66
Converted Constellation options	11,194,151	41.35
Vested [b][c]	(12,023,432)	41.37
Forfeited	(459,104)	49.45
Nonvested at December 31, 2012 [a]	1,960,665	$40.56

(a) Excludes 2,647,536 and 1,348,000 of stock options issued to retirement-eligible employees as of December 31, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Includes 8,684,709 of converted Constellation options that were vested prior to the Merger on March 12, 2012.
(c) Includes 1,699,000 of stock options issued to retirement-eligible employees in 2012 that vested immediately upon the employee reaching retirement eligibility.

At December 31, 2012, $6 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted-average period of 2.4 years.

Restricted Stock Units

Restricted stock units are granted under the LTIP with the majority being settled in a specific number of shares of common stock after the service condition has been met. The corresponding cost of services is measured based on the grant date fair value of the restricted stock unit issued.

The value of the restricted stock units is expensed over the requisite service period using the straight-line method. The requisite service period for restricted stock units is generally three to five years. However, certain restricted stock unit awards become fully vested upon the employee reaching retirement-eligibility. The value of the restricted stock units granted to retirement-eligible employees is either recognized immediately upon the date of grant or through the date at which the employee reaches retirement eligibility. Exelon uses historical data to estimate employee forfeitures, which are compared to actual forfeitures on a quarterly basis and adjusted as necessary.

The following table summarizes Exelon's nonvested restricted stock unit activity for the year ended December 31, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011 [a]	1,074,484	$48.08
Granted	1,332,214	39.94
Converted Constellation restricted stock	825,735	38.91
Vested	(479,805)	46.36
Forfeited	(76,484)	42.21
Undistributed vested awards [b]	(646,983)	40.75
Nonvested at December 31, 2012 [a]	2,029,161	$42.12

(a) Excludes 686,121 and 448,827 of restricted stock units issued to retirement-eligible employees as of December 31, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement-eligible employees during 2012.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2012, 2011 and 2010 was $39.94, $43.33 and $44.23, respectively. At December 31, 2012 and 2011, Exelon had obligations related to outstanding restricted stock units not yet settled of $58 million and $46 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2012, 2011 and 2010, Exelon settled restricted stock units with fair value totaling $25 million, $19 million and $22 million, respectively. At December 31, 2012, $43 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted-average period of 1.9 years.

Performance Share Awards

Performance share awards are granted under the LTIP with the 2012 performance share awards being settled in 50% common stock and 50% cash over the three-year vesting term. The 2011 performance share awards are being settled entirely in common stock over the three-year vesting term. The performance shares granted prior to 2011 generally vest and settle over a three-year period with the holders receiving shares of common stock and/or cash annually during the vesting period.

These awards are recorded at fair value at the date of grant with the estimated grant date fair value based on the expected payout of the award, which may range from 75% to 125% of the payout target. The common stock portion is considered an equity award with the 75% payout floor being valued based on Exelon's stock price on the grant date. The cash portion of the award is considered a liability award with the 75% payout floor being remeasured each reporting period based on Exelon's current stock price. The expected payout in excess of the 75% floor for the equity and liability portions are remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore these portions of the award are subject to volatility until the payout is established.

In 2010, the number of performance shares granted was determined based on the performance of Exelon's common stock relative to certain stock market indices during the three-year period through the end of the year of grant. These performance share awards generally vest and settle over a three-year period. The holders of these performance share awards receive shares of common stock and/or cash annually during the vesting period. Participants are eligible for partial or full distributions in cash if they meet certain stock ownership requirements.

The 2010 performance share awards that were settled in stock were recorded as common stock within the Consolidated Balance Sheets and recorded at fair value at the date of grant. The grant date fair value of equity classified performance share awards granted during the year ended 2010 was estimated using historical data for the previous two plan years and a Monte Carlo simulation model for the current plan year. This model requires assumptions regarding Exelon's total shareholder return relative to certain stock market indices and the stock beta and volatility of Exelon's common stock and all stocks represented in these indices. Volatility for Exelon and all comparable companies is based on historical volatility over one year using daily stock price observation. The 2010 performance share awards that were settled in cash were recorded as liabilities within the Consolidated Balance Sheets. The grant date fair value of liability classified performance share awards granted during the year ended 2010 was based on historical data for the previous two plan years and actual results for the current plan year. The liabilities were remeasured each reporting period throughout the requisite service period and as a result, the compensation costs for cash-settled awards were subject to volatility.

For non retirement-eligible employees, stock-based compensation costs are recognized over the vesting period of three years using the graded-vesting method, a method in which the compensation cost is recognized over the requisite service period for each separately vesting tranche of the award as though the award were multiple awards. For performance shares granted to retirement-eligible employees, the value of the performance shares is recognized ratably over the vesting period which is the year of grant.

The following table summarizes Exelon's nonvested performance share awards activity for the year ended December 31, 2012:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2011 (a)	346,848	$45.37
Granted	1,429,189	39.72
Vested	(167,048)	47.46
Forfeited	(116,388)	39.78
Undistributed vested awards (b)	(179,867)	40.72
Nonvested at December 31, 2012 (a)	1,312,734	$40.08

(a) Excludes 204,643 and 455,418 of performance share awards issued to retirement-eligible employees as of December 31, 2012 and December 31, 2011, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement-eligible employees during 2012.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2012, 2011 and 2010 was $39.71, $43.52 and $60.82 respectively. During the years ended December 31, 2012, 2011 and 2010, Exelon settled performance shares with a fair value totaling $23 million, $22 million and $32 million, respectively, of which $3 million,

$10 million and $20 million was paid in cash, respectively. As of December 31, 2012, $9 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted-average period of 2.2 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31,	
	2012	2011
Current liabilities (a)	$ 7	$ 3
Deferred credits and other liabilities (b)	11	—
Common stock	35	30
Total	$53	$ 33

(a) Represents the current liability related to performance share awards expected to be settled in cash.
(b) Represents the long-term liability related to performance share awards expected to be settled in cash.

18. Earnings Per Share and Equity

Earnings per Share

Diluted earnings per share is calculated by dividing net income by the weighted average number of shares of common stock outstanding, including shares to be issued upon exercise of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs considered to be common stock equivalents. The following table sets forth the components of basic and diluted earnings per share and shows the effect of these stock options, performance share awards and restricted stock on the weighted average number of shares outstanding used in calculating diluted earnings per share:

	Year Ended December 31,		
	2012	2011	2010
Net income on common stock	$1,160	$2,495	$2,563
Weighted average common shares outstanding—basic	816	663	661
Assumed exercise and/or distributions of stock-based awards	3	2	2
Weighted average common shares outstanding—diluted	819	665	663

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 14 million in 2012, 9 million in 2011 and 8 million in 2010.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of December 31, 2012. In 2008, Exelon management decided to defer indefinitely any share repurchases.

19. Commitments and Contingencies

Nuclear Insurance

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of December 31, 2012, the current liability limit per incident was $12.6 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective October 29, 2008. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of January 1, 2013, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 104 reactors) resulting in an additional $12.2 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $117.5 million, payable at no more than $17.5 million per reactor per incident per year. Exelon's maximum liability per incident is approximately $2.2 billion. In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $12.6 billion limit for a single incident.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL may declare distributions to its members as a result of favorable operating experience. In recent years NEIL has made distributions to its members, but Generation cannot predict the level of future distributions or if they will continue at all. No distributions were declared in 2011 or 2012. Premiums paid to NEIL by its members are subject to assessment (the retrospective premium obligation) for adverse loss experience. NEIL has never exercised this assessment since its formation in 1973, and while Generation cannot predict the level of future assessments, or if they will be imposed at all, as of December 31, 2012, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $278 million.

NEIL provides "all risk" property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. As of December 31, 2012, Generation's current limit for this coverage is $2.1 billion. For property limits in excess of the first $1.25 billion of that limit, Generation participates in an $850 million single limit blanket policy shared by all the Generation operating nuclear sites and the Salem and Hope Creek nuclear sites. This blanket limit is not subject to automatic reinstatement in the event of a loss. In the event of an accident, insurance proceeds must first be used for reactor stabilization and site decontamination. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. Under the terms of the various insurance agreements, Generation could be assessed up to $220 million per year for losses incurred at any plant insured by the insurance company (the retrospective premium obligation). In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses. The $3.2 billion maximum recovery limit is not applicable, however, in the event of a "certified act of terrorism" as defined in the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007. The Terrorism Risk Insurance Act expires on December 31, 2014.

Additionally, NEIL provides replacement power cost insurance in the event of a major accidental outage at an insured nuclear station. The premium for this coverage is subject to assessment for adverse loss experience. Generation's maximum share of any assessment is $58 million per year (the retrospective premium obligation). Recovery under this insurance for terrorist acts is subject to the $3.2 billion aggregate limit and secondary to the property insurance described above. This limit would not apply in cases of certified acts of terrorism under the Terrorism Risk Insurance Act of 2002, as amended by the Terrorism Risk Insurance Program Reauthorization Act of 2007, as described above.

Effective April 1, 2009, NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon's and Generation's financial condition, results of operations and liquidity.

Spent Nuclear Fuel Obligation

Under the NWPA, the DOE is responsible for the development of a geologic repository for and the disposal of SNF and high-level radioactive waste. As required by the NWPA, Generation is a party to contracts with the DOE (Standard Contracts) to provide for disposal of SNF from Generation's nuclear generating stations. In accordance with the NWPA and the Standard Contracts, Generation pays the DOE one mill ($0.001) per kWh of net nuclear generation for the cost of SNF disposal. This fee may be adjusted prospectively in order to ensure full cost recovery. The NWPA and the Standard Contracts required the DOE to begin taking possession of SNF generated by nuclear generating units by no later than January 31, 1998. The DOE, however, failed to meet that deadline and its performance will be delayed significantly.

The 2010 Federal budget (which became effective October 1, 2009) eliminated almost all funding for the creation of the Yucca Mountain repository while the Obama administration devises a new strategy for long-term SNF management. In early 2010, Secretary of Energy Steven Chu appointed the Blue Ribbon Commission (BRC) on America's Nuclear Future to evaluate and recommend a new plan for managing the back end of the nuclear fuel cycle, including used fuel storage, disposal and fees. The Commission released its final report to the U.S. Energy Secretary on January 26, 2012, detailing comprehensive recommendations for creating a safe, long-term solution for managing and disposing of the nation's spent nuclear fuel and high-level radioactive waste. The strategy recommended by the Commission encompasses 8 key elements; 1) A new consent-based approach to siting storage and disposal facilities; 2) A new organization to implement the waste management program; 3) Access to utility waste disposal fees for their intended purpose; 4) Prompt efforts to develop a new geological disposal facility; 5) Prompt efforts to develop one or more consolidated storage facilities; 6) Early preparation for the eventual large-scale transport of spent nuclear fuel and high-level waste to consolidated storage and disposal facilities; 7) Support for advances in nuclear energy technology and for workforce development; and 8) Active U.S. leadership in international efforts to address safety, non-proliferation and security concerns.

In early 2013, the DOE issued an updated "Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste" in response to the BRC recommendations. This strategy included a consolidated interim storage facility that is planned to be operational in 2025.

Generation uses the 2025 date as the assumed date for when the DOE will begin accepting SNF for purposes of determining nuclear decommissioning asset retirement obligations. The extended delay in SNF acceptance by the DOE has led to Generation's adoption of dry cask storage at its Dresden, Clinton, Limerick, Oyster Creek, Peach Bottom, Byron, Braidwood, LaSalle and Quad Cities stations. Generation performed sensitivity analyses assuming that the estimated date for the DOE acceptance of SNF was delayed to 2030 and determined that Generation's aggregate nuclear ARO would be increased by approximately $700 million.

In August 2004, Generation and the DOJ, in close consultation with the DOE, reached a settlement under which the government agreed to reimburse Generation, subject to certain damage limitations based on the extent of the government's breach, for costs associated with storage of SNF at Generation's nuclear stations pending the DOE's fulfillment of its obligations. Generation submits annual reimbursement requests to the DOE for costs associated with the storage of SNF. In all cases, reimbursement requests are made only after costs are incurred and only for costs resulting from DOE delays in accepting the SNF.

Under the settlement agreement, Generation has received cash reimbursements for costs incurred through April 30, 2012, totaling approximately $639 million ($543 million after considering amounts due to co-owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2012, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $61 million, which is recorded within accounts receivable, other. Of this amount, $13 million represents amounts owed to the co-owners of the Peach Bottom and Quad Cities generating facilities.

CENG has entered into settlement agreements with the DOE during 2011 and 2012 to recover damages caused by the DOE's failure to comply with legal and contractual obligations to dispose of spent nuclear fuel related to the Ginna, Calvert Cliffs and Nine Mile Point nuclear power plants. At December 31, 2012, Generation had approximately $22 million recorded as a receivable from CENG with respect to costs incurred by Constellation prior to November 6, 2009, for the Nine Mile Point and Calvert Cliffs nuclear power plants. CENG received the funds for the Nine Mile Point and Calvert Cliffs settlement from the DOE in January 2013 and February 2013, respectively, and remitted the $22 million to Generation.

The Standard Contracts with the DOE also required the payment to the DOE of a one-time fee applicable to nuclear generation through April 6, 1983. The fee related to the former PECO units has been paid. Pursuant to the Standard Contracts, ComEd previously elected to defer payment of the one-time fee of $277 million for its units (which are now part of Generation), with interest to the date of payment, until just prior to the first delivery of SNF to the DOE. As of December 31, 2012, the unfunded SNF liability for the one-time fee with interest was $1,020 million. Interest accrues at the 13-week Treasury Rate. The 13-week Treasury Rate in effect, for calculation of the interest accrual at December 31, 2012, was 0.127%. The liabilities for SNF disposal costs, including the one-time fee, were transferred to Generation as part of the 2001 corporate restructuring. The outstanding one-time fee obligations for the Oyster Creek and TMI units remain with the former owners. Clinton has no outstanding obligation. See Note 9—Fair Value of Assets and Liabilities for additional information.

Energy Commitments

Generation's customer facing activities include the physical delivery and marketing of power obtained through its generation capacity, and long-, intermediate- 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. These agreements are firm commitments related to power generation of specific generation plants and/or are dispatchable in nature. Several of Generation's long-term PPAs, which have been determined to be operating leases, have significant contingent rental payments that are dependent on the future operating characteristics of the associated plants, such as plant availability. Generation recognizes contingent rental expense when it becomes probable of payment. Generation enters into PPAs with the objective of obtaining low-cost energy supply sources to meet its physical delivery obligations to its customers. Generation has also purchased firm transmission rights to ensure that it has reliable transmission capacity to physically move its power supplies to meet customer delivery needs. The primary intent and business objective for the use of its capital assets and contracts is to provide Generation with physical power supply to enable it to deliver energy to meet customer needs. In addition to physical contracts, Generation uses financial contracts for economic hedging purposes and, to a lesser extent, as part of proprietary trading activities.

Generation has entered into bilateral long-term contractual obligations for sales of energy to load-serving entities, including electric utilities, municipalities, electric cooperatives and retail load aggregators. Generation also enters into contractual obligations to deliver energy to market participants who primarily focus on the resale of energy products for delivery. Generation provides for delivery of its energy to these customers through firm transmission.

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 below commitments to purchase from CENG at fixed prices. All commitments to purchase 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—Related Party Transactions for more details on this arrangement.

At December 31, 2012, Generation's short- and long-term commitments, relating to the purchases from unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	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.

Pursuant to a PPA with Public Service Company of Oklahoma, a subsidiary of American Electric Power Company, Inc., dated as of April 17, 2009, Generation agreed to sell its rights to up to 520 MWs, or approximately two-thirds of the capacity, energy and ancillary services supplied under its existing long-term contract with Green Country Energy, LLC. The delivery of power under the PPA commenced June 1, 2012 and will run through February 28, 2022.

ComEd purchases its expected energy requirements through an ICC approved competitive bidding process administered by the IPA, existing ICC approved RFPs, and spot market purchases hedged with a financial swap contract with Generation expiring in 2013. See Note 3—Regulatory Matters for further information.

PECO's long-term PPA with Generation, under which PECO obtained all of its electric supply from Generation for a 12-year period, expired on December 31, 2010. During 2009, 2010, 2011 and 2012, PECO entered into contracts through a competitive procurement process in order to meet a portion of its default service customers' electric supply requirements for 2011 through 2015. See Note 3—Regulatory Matters for further information regarding the DSP Programs.

ComEd is subject to requirements established by the Illinois Settlement Legislation and the Energy Infrastructure Modernization Act related to the use of alternative energy resources. PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. BGE is subject to requirements established by the Public Utilities Article in Maryland related to the use of alternative energy resources; however, the wholesale suppliers that supply power to BGE through SOS procurement auctions have the obligation, by contract with BGE, to meet the RPS requirement. BGE has entered into contracts with curtailment services providers in accordance with the March 2009 MDPSC order. See Note 3—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments as of December 31, 2012 are as follows:

		Expiration within					
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
ComEd							
Electric supply procurement [a]	$1,103	$367	$323	$136	$137	$140	$ —
Renewable energy and RECs [b]	1,661	71	73	74	76	82	1,285
PECO							
Electric supply procurement [c]	799	561	200	38	—	—	—
AECs	33	12	9	2	2	2	6
BGE							
Electric supply procurement [d]	1,401	859	467	75	—	—	—
Curtailment services	153	49	47	41	16	—	—

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2017. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. See Note 3—Regulatory Matters for additional information.

(b) ComEd entered into 20-year contracts for renewable energy and RECs beginning June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. Per the ICC's Final Commission Order on December 19, 2012, the quantities purchased under these long-term renewable contracts should be curtailed during the June 2013—May 2014 period to avoid exceeding the statutory rate impact for affected customers as a result of an increased number of ComEd's customers purchasing their energy from alternative energy suppliers. See Note 3—Regulatory Matters for additional information.

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2013 and 2015. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 3—Regulatory Matters for additional information.

(d) BGE entered into various contracts for the procurement of electricity beginning 2012 through 2015. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3—Regulatory Matters for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation (and with respect to coal, commitments to sell coal). PECO and BGE have commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2012, these net commitments were as follows:

		Expiration within					
	Total	**2013**	**2014**	**2015**	**2016**	**2017**	**2018 and beyond**
Generation	$8,857	$1,276	$1,207	$1,272	$976	$1,064	$3,062
PECO	444	145	87	71	49	15	77
BGE	654	133	73	54	52	52	290

Other Purchase Obligations

The Registrants' other purchase obligations as of December 31, 2012, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Exelon	$716	$186	$167	$114	$ 51	$ 49	$149
Generation	487	127	120	94	32	29	85
ComEd	8	2	6	—	—	—	—
PECO	45	17	18	1	1	1	7
BGE	—	—	—	—	—	—	—

Commercial Commitments

Exelon's commercial commitments as of December 31, 2012, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2013	2014	2015	2016	2017	2018 and beyond
Letters of credit (non-debt) [(a)]	$ 1,889	$ 1,325	$ —	$564	$—	$—	$ —
Surety bonds [(b)]	286	225	—	1	6	4	50
Performance guarantees [(c)]	1,897	908	203	—	—	—	786
Energy marketing contract guarantees [(d)]	8,556	8,556	—	—	—	—	—
Lease guarantees [(e)]	48	—	—	—	—	—	48
Middle market lending commitments [(f)]	180	180	—	—	—	—	—
Nuclear insurance premiums [(g)]	2,494	—	—	—	—	—	2,494
Total commercial commitments	$15,350	$11,194	$203	$565	$ 6	$ 4	$3,378

(a) Letters of credit (non-debt)—Exelon and certain of its subsidiaries maintain non-debt letters of credit to provide credit support for certain transactions as requested by third parties.

(b) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

(c) Performance guarantees—Guarantees issued to ensure performance under specific contracts, including $211 million issued on behalf of CENG nuclear generating facilities for credit support, $200 million of Trust Preferred Securities of ComEd Financing III, $178 million of Trust Preferred Securities of PECO Trust III and IV and $250 million of Trust Preferred Securities of BGE Capital Trust II.

(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts. Amount includes approximately $8.3 billion of guarantees previously issued by Constellation on behalf of its Generation and NewEnergy business to allow it the flexibility needed to conduct business with counterparties without having to post other forms of collateral. The majority of these guarantees contain evergreen provisions that require the guarantee to remain in effect until cancelled. Exelon's estimated net exposure for obligations under commercial transactions covered by these guarantees is approximately $1.5 billion at December 31, 2012, which represents the total amount Exelon could be required to fund based on December 31, 2012 market prices.

(e) Lease guarantees—Guarantees issued to ensure payments on building leases.

(f) Middle market lending commitments—Represents commitments to investment in loans or managed funds which invest in private companies. These commitments will be funded by Generation's existing nuclear decommissioning trust funds. See Note 9—Fair Value of Financial Assets and Liabilities for more information on nuclear decommissioning trust funds and middle market lending.

(g) Nuclear insurance premiums—Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. The first portion of the project began operations in December 2012, with additional phases to come online and an expectation of full commercial operation by the end of the third quarter of 2013. Generation's estimated remaining commitment for the project is $636 million for 2013. See Note 4—Merger and Acquisitions for additional information.

Refer to Note 3—Regulatory Matters for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan, BGE's comprehensive smart grid initiative and ComEd's, PECO's and BGE's commitment to construct transmission facilities under their operating agreements with PJM.

Constellation Merger Commitments

Exelon's commercial and construction commitments shown above do not include the merger commitments made to the State of Maryland in conjunction with the Constellation merger. See Note 4—Merger and Acquisitions for additional information on the merger commitments.

Leases

Minimum future operating lease payments, including lease payments for vehicles, real estate, computers, rail cars, operating equipment and office equipment, as of December 31, 2012 were:

2013	$ 88
2014	83
2015	73
2016	69
2017	63
Remaining years	488
Total minimum future lease payments[(a)(b)(c)]	$864

(a) Excludes Generation's PPAs and other capacity contracts that are accounted for as contingent operating lease payments.

(b) Amounts related to certain real estate leases and railroad licenses effectively have indefinite payment periods. As a result, Exelon has excluded these payments from the remaining years, as such amounts would not be meaningful. Exelon's annual obligation for these arrangements, included in each of the years 2013—2017, was $5 million.

(c) Includes all future lease payments on a 99 year real estate lease that expires in 2105.

The following table presents Exelon's rental expense under operating leases for the years ended December 31, 2012, 2011 and 2010:

For the Year Ended December 31,[(a)]	
2012	$930
2011	711
2010	722

(a) Includes Generation's PPAs and other capacity contracts that are accounted for as operating leases and are reflected as net capacity purchases in the energy commitments table above. These agreements are considered contingent operating lease payments and are not included in the minimum future operating lease payments table above. Payments made under Generation's PPAs and other capacity contracts totaled $801 million, $630 million and $641 million during 2012, 2011 and 2010, respectively.

For information regarding capital lease obligations, see Note 11—Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe

On January 31, 2005, subsidiaries of Generation completed a series of transactions that resulted in Generation's sale of its investment in Sithe. Specifically, subsidiaries of Generation consummated the acquisition of Reservoir Capital Group's 50% interest in Sithe and subsequently sold 100% of Sithe to Dynegy Inc. (Dynegy).

The estimated maximum possible exposure to Exelon related to the guarantees provided as part of the sales transaction to Dynegy was approximately $200 million at December 31, 2012. Generation believes that it is remote that it will be required to make any additional payments under the guarantee, and currently has no recorded liabilities associated with this guarantee. Generation expects that the exposure covered by this guarantee will expire in 2014. The guarantee is included above in the Commercial Commitments table under performance guarantees.

Indemnifications Related to Sale of TEG and TEP

On February 9, 2007, Tamuin International Inc. (TII), a wholly owned subsidiary of Generation, sold its 49.5% ownership interests in TEG and TEP to a subsidiary of AES Corporation for $95 million in cash plus certain purchase price adjustments. In connection with the transaction, Generation entered into a guarantee agreement under which Generation guarantees the timely payment of TII's obligations to the subsidiary of AES Corporation pursuant to the terms of the purchase and sale agreement relating to the sale of TII's ownership interests. Generation would be required to perform in the event that TII does not pay any obligation covered by the guarantee that is not otherwise subject to a dispute resolution process. Generation's maximum obligation under the guarantee is $95 million as of December 31, 2012. Generation believes that it is remote that it will be required to make payments under the guarantee, and has not recorded a liability associated with this guarantee. The exposures covered by this guarantee expired in part during 2008. Generation expects that the remaining exposure will expire in 2013. The guarantee of $95 million is included above in the Commercial Commitments table under performance guarantees.

Environmental Matters

General. Exelon's operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, Exelon is generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. Exelon owns or leases a number of real estate parcels, including parcels on which its operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, Exelon is currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For many of these sites, ComEd, PECO or BGE is one of several PRPs that may be responsible for ultimate remediation of each location.

- ComEd has identified 42 sites, 13 of which have been approved for cleanup by the Illinois EPA or the U.S. EPA and 27 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2016.
- PECO has identified 26 sites, 16 of which have been approved for cleanup by the PA DEP and 10 that are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2019.
- BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. One gas purification site is in the initial stages of investigation at the direction of the MDE.

Pursuant to orders from the ICC, PAPUC and MDPSC, respectively, ComEd, PECO and BGE are authorized to and are currently recovering environmental costs for the remediation of former MGP facility sites from customers, for which they have recorded regulatory assets. ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are recovering 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 in distribution rates. During the second and third quarters of 2012, ComEd and PECO completed annual studies of their future estimated MGP remediation requirements. The results of these studies indicated that additional remediation would be required at certain sites; accordingly, ComEd and PECO increased their reserves and regulatory assets by $146 million and $7 million, respectively. BGE assessed its currently and formerly owned gas manufacturing and purification sites quarterly in 2012 and determined that a loss was not probable at ten of its sites as of December 31, 2012. As discussed above, the remediation costs at two of BGE's MGP sites are not considered material. Furthermore, an estimate of a range of possible loss, if any, related to BGE's gas purification site under investigation cannot be determined as of December 31, 2012 given that the site is in the early stages of investigation and any potential contamination is currently unknown. See Note 3—Regulatory Matters for additional information regarding the associated regulatory assets.

This historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs based on probabilistic and deterministic modeling using all available information at the time of each study and the remediation standards currently required by the U.S. EPA. The increase in the reserve at ComEd was predominately tied to 6 sites with a total increase of approximately $111 million. The change was driven by the completion of additional preliminary environmental investigations that identified increases in scope for the remediation of larger areas and to greater depths, along with the requirement for additional groundwater management not previously contemplated in prior studies. ComEd also obtained new information on scope requirements for several sites where another PRP is leading remediation efforts and that ComEd shares responsibility. Prior to completion of any significant clean up, each site remediation plan is approved by the Illinois EPA.

As of December 31, 2012 and 2011, Exelon has accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within its Consolidated Balance Sheets:

	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
2012	$338	$298

	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
2011	$224	$168

Exelon cannot reasonably estimate whether it will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by Exelon, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water Quality

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

On March 28, 2011, the U.S. EPA issued the proposed regulation under Section 316(b). The proposal does not require closed-cycle cooling (e.g., cooling towers) as the best technology available to address impingement and entrainment. The proposal provides the state permitting agency with discretion to determine the best technology available to limit entrainment (drawing aquatic life into the plants cooling system) mortality, including application of a cost-benefit test and the consideration of a number of site-specific factors. After consideration of these factors, the state permitting agency may require closed cycle cooling, an alternate technology, or determine that the current technology is the best available. The proposed rule also imposes limits on impingement (trapping aquatic life on screens) mortality, which likely will be accomplished by the installation of screens or similar technology at the intake. Exelon filed comments on the proposed regulation on August 18, 2011, stating its support for a number of its provisions (e.g., cooling towers not required as best technology available, and the use of site-specific and cost benefit analysis) while also noting a number of technical provisions that require revision to take into account existing unit operations and practices within the industry.

In June 2012, the U.S. EPA published two Notices of Data Availability (NODA) seeking public comment on alternate compliance technologies for impingement and the use of a public opinion survey to calculate the so-called "non-use" benefits of the rule. Exelon filed comments for each NODA, supporting the additional flexibility afforded by the impingement NODA, and opposing the NODA relating to calculation of non-use benefits due to its inaccurate and unreliable methodologies that would artificially inflate the benefits of proposed technologies that would otherwise not be cost-effective. On July 18, 2012, the U.S. EPA announced that it had agreed to extend the court approved Settlement Agreement to extend the deadline to issue a final rule until June 27, 2013. Until the rule is finalized, the state permitting agencies will continue to apply their best professional judgment to address impingement and entrainment.

Oyster Creek. On January 7, 2010, the NJDEP issued a draft NPDES permit for Oyster Creek that would have required, in the exercise of its best professional judgment, the installation of cooling towers as the best technology available within seven years after the effective date of the permit. On December 8, 2010, Exelon announced that Generation will permanently cease generation operations at Oyster Creek no later than December 31, 2019. The current NRC license for Oyster Creek expires in 2029. In reliance upon Exelon's determination to cease generation operations no later than December 31, 2019, the NJDEP determined that closed cycle cooling is not the best technology available for Oyster Creek given the length of time that would be required to retrofit from the existing once-through cooling system to a closed-cycle cooling system and the limited life span of the plant after installation of a closed-cycle cooling system. Based on its consideration of these and other factors, NJDEP determined that the existing measures at the plant represent the best technology available for the facility's cooling water intake through cessation of generation operations.

On December 9, 2010, Generation executed an Administrative Consent Order (ACO) with the NJDEP regarding Oyster Creek. The ACO sets forth, among other things, the agreement by Generation to permanently cease generation operations at Oyster Creek if the conditions of the ACO are satisfied. In accordance with the ACO, on December 21, 2011, the NJDEP agreed to issue a final NPDES permit that became effective on April 12, 2012 that does not require the construction of cooling towers or other closed-cycle cooling facilities. The ACO and the final permit apply only to Oyster Creek based on its unique circumstances and does not set any precedent for the ultimate compliance requirements for Section 316(b) at Exelon's other plants.

As a result of the decision and the ACO, the expected economic useful life of Oyster Creek was reduced by 10 years to correspond to Exelon's current best estimate as to the timing of ceasing generation operations at the Oyster Creek unit in 2019. The financial impacts relate primarily to accelerated depreciation and accretion expense associated with the changes in decommissioning assumptions related to Generation's asset retirement obligation over the remaining expected economic useful life of Oyster Creek.

Salem and Other Power Generation Facilities. In June 2001, the NJDEP issued a renewed NPDES permit for Salem, allowing for the continued operation of Salem with its existing cooling water system. NJDEP advised PSEG in July 2004 that it strongly recommended reducing cooling water intake flow commensurate with closed-cycle cooling as a compliance option for Salem. PSEG submitted an application for a renewal of the permit on February 1, 2006. In the permit renewal application, PSEG analyzed closed-cycle cooling and other options and demonstrated that the continuation of the Estuary Enhancement Program, an extensive environmental restoration program at Salem, is the best technology to meet the Section 316(b) requirements. PSEG continues to operate Salem under the approved June 2001 NPDES permit while the NPDES permit renewal application is being reviewed. If the final permit or Section 316(b) regulations ultimately requires the retrofitting of Salem's cooling water intake structure to reduce cooling water intake flow commensurate with closed-cycle cooling, Exelon's and Generation's share of the total cost of the retrofit and any resulting interim replacement power would likely be in excess of $430 million, based on a 2006 estimate, and would result in increased depreciation expense related to the retrofit investment.

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

Given the uncertainties associated with the requirements that will be contained in the final rule, Generation cannot predict the eventual outcome or estimate the effect that compliance with any resulting Section 316(b) or interim state requirements will have on the operation of its and CENG's generating facilities and its future results of operations, cash flows and financial position.

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Prior to the merger, Constellation recorded a liability in its Consolidated Balance Sheets of approximately $23 million to comply with the consent decree. The remaining liability as of December 31, 2012, is approximately $3 million. In addition, a private party has asserted claims relating to groundwater contamination. The company believes that these claims are without merit and is vigorously contesting them.

Alleged Conemaugh Clean Streams Act Violation. The PA DEP has alleged that GenOn Northeast Management Company (GenOn), the operator of Conemaugh Generating Station, violated the Pennsylvania Clean Streams Law. GenOn reached agreement with PA DEP on a proposed Consent Order that was approved by the Commonwealth Court of Pennsylvania on December 4, 2012. Under the Consent Order, GenOn is obligated to pay a civil penalty of $0.5 million, of which Generation's responsibility is approximately $0.2 million.

Air Quality

Cross-State Air Pollution Rule (CSAPR). On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR, which had been promulgated by the U.S. EPA to reduce power plant emissions of SO_2 and NO_x. The D.C. Circuit Court later remanded the CAIR to the U.S. EPA, without invalidating the entire rulemaking, so that the U.S. EPA could correct CAIR in accordance with the D.C. Circuit Court's July 11, 2008 opinion. On July 7, 2011, the U.S. EPA published the final rule, known as the CSAPR. The CSAPR requires 28 states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in other states.

Numerous entities challenged the CSAPR in the D.C. Circuit Court, and some requested a stay of the rule pending the Court's consideration of the matter on the merits. On December 30, 2011, the Court granted a stay of the CSAPR, and directed the U.S. EPA to continue the administration of CAIR in the interim. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA has exceeded its authority in certain material aspects of the CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On January 24, 2013, the Court denied petitions for reconsideration of the ruling by the three-judge panel.

Under the CSAPR, Generation units were to receive allowances based on historic heat input, and intrastate and limited interstate trading of allowances was permitted. The CSAPR restricted entirely the use of pre-2012 allowances. Existing SO_2 allowances under the ARP would remain available for use under ARP. During the third quarter of 2010, Generation recognized a lower of cost or market impairment charge of $57 million on its ARP SO_2 allowances that were not expected to be used by Generation's fossil-fuel power plants and that had not been sold forward. The impairment was recorded due to the significant decline of allowance market prices because CSAPR regulations would restrict entirely the use of ARP SO_2 allowances beginning in 2012. As of December 31, 2012, Generation had $45 million of emission allowances carried at the lower of weighted average cost or market.

EPA Mercury and Air Toxics Standards (MATS). The MATS rule became final on April 16, 2012. The MATS rule reduces emissions of toxic air pollutants, and finalized the new source performance standards for fossil fuel-fired electric utility steam generating units (EGUs). The MATS rule requires coal-fired EGUs to achieve high removal rates of mercury, acid gases and other metals from air emissions. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that smaller, older, uncontrolled coal units will retire rather than make these investments. Coal units with existing controls that do not meet the required standards may need to upgrade existing controls or add new controls to comply. In addition, the new standards will cause oil units to achieve high removal rates of metals. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities have challenged MATS in the D.C. Circuit Court, and Exelon was granted permission by the Court to intervene in support of the rule. A decision by the Court is not expected until sometime in 2013. The outcome of the appeal, and its impact on power plant operators' investment and retirement decisions, is uncertain.

Exelon, along with the other co-owners of Conemaugh Generating Station are moving forward with plans to improve the existing scrubbers and install Selective Catalytic Reduction (SCR) controls to meet the mercury removal requirements of MATS.

In addition, as of December 31, 2012, Exelon had a $693 million net investment in coal-fired plants in Georgia and Texas subject to long-term leases extending through 2028-2032. While Exelon currently estimates the value of these plants at the end of the lease term will be in excess of the recorded residual lease values, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

National Ambient Air Quality Standards (NAAQS). The U.S. EPA previously announced that it would complete a review of the NAAQS by 2014. In December 2012, the U.S. EPA issued a more stringent particulate matter NAAQS. The Agency is currently evaluating its 2008 ozone NAAQS for potentially more stringent requirements as was previously recommended by the U.S. EPA Clean Air Act Scientific Advisory Committee (CASAC) when it reviewed the 2008 ozone NAAQS (that is currently the subject of litigation in the D.C. Circuit Court). These final and pending NAAQS reviews could result in more stringent emissions limits on fossil-fired electric generating stations. In July 2012, the D.C. Circuit Court issued separate rules upholding tightened NAAQS established by the U.S. EPA in 2010 for nitrogen dioxide and sulfur dioxide. The rulings clear the way for the U.S. EPA to continue work already underway with state and local agencies on implementing revised SIP's designed to achieve or maintain the required air quality levels. To the extent not already impacted by CAIR (and in the future by CSAPR after revision upon remand) and MATS, some power plants could be required to achieve further reductions of nitrogen dioxide and sulfur dioxide emissions.

In September 2011, the U.S. EPA withdrew its reconsideration of the NAAQS standard for ozone, which is next scheduled for reconsideration in 2014. Litigation of the ozone standard in the D.C. Circuit Court continues. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation. It is unclear if the vacatur of the CSAPR, one of the regulations that the U.S. EPA is relying on to assist with future PM reduction, would alter the U.S. EPA's view since either CAIR or a finalized CSAPR regulation would be in effect leading up to 2020.

In addition to these NAAQS, the U.S. EPA also expects to finalize initial designations for the 2010 one-hour SO_2 standard in June 2013 and require states to submit state implementation plans (SIPs) for nonattainment areas by February 2015. Compliance with the one-hour SO_2 standard is required by February 2018. While significant SO_2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the U.S. EPA's final one-hour SO_2 standard designation methodology at this point in time as the U.S. EPA continues to consider whether to used modeled or monitored data to inform the designation process, nor potential SIP requirements for areas found to be in nonattainment.

Notices and Finding of Violations and Midwest Generation Bankruptcy. In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

On August 6, 2007, ComEd received a NOV addressed to it and Midwest Generation from the U.S. EPA, alleging, in relevant part, that ComEd and Midwest Generation violated and are continuing to violate provisions of the Clean Air Act as a result of the modification and/or operation of six electric generation stations located in northern Illinois that have been owned and operated by Midwest Generation since their purchase from ComEd in 1999. In August 2009, the United States and the State of Illinois filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to most of the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon was named as a defendant in this original complaint. In March 2010, the District Court granted Midwest Generation's partial motion to dismiss all but one of the claims against Midwest Generation. The District Court held that Midwest Generation cannot be liable for any alleged violations relating to construction that occurred prior to Midwest Generation's ownership of the stations. In May 2010, the government plaintiffs filed an amended complaint against Midwest Generation asserting claims substantially similar to those in the original complaint, and added ComEd and EME as defendants. The amended complaint seeks injunctive relief and civil penalties against all defendants, although not all of the claims specifically pertain to ComEd. On March 16, 2011, the District Court granted ComEd's motion to dismiss the May 2010 complaint in its entirety as it relates to ComEd. On January 3, 2012, upon leave of the District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals for the Seventh Circuit. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, however, Exelon, Generation and ComEd have concluded that, in light of the March 2011 District Court decision, the likelihood of loss is remote. Therefore, no reserve has been established.

On December 17, 2012, EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code (the "Petition Date").

As a result of the bankruptcy filing, Exelon and Generation have recorded liabilities and receivable reserves as of December 31, 2012, for a total of $13 million, which consists primarily of lease payments under a coal rail car lease and estimated payments for asbestos personal injury claims filed pre-Petition Date. The Bankruptcy Court approved the rejection of the agreement under which Midwest Generation was responsible for obligations under the lease, leaving Generation as the party responsible to make remaining payments under the lease. Exelon and Generation currently expect Midwest Generation or its successor will remain responsible for asbestos personal injury claims filed post-Petition Date, and as such have recorded no liability for such amounts. Requirements for Generation to ultimately satisfy such claims could have a material adverse impact on Exelon's and Generation's future results of operations.

As of the Petition Date, Generation had wholesale power transactions with Edison Mission Marketing and Trading, an affiliate of Midwest Generation not included in the bankruptcy proceeding. Generation expects these transactions to be fully settled in the normal course.

Certain environmental laws and regulations subject current and prior owners of properties or generators of hazardous substances at such properties to liability for remediation costs of environmental contamination. As a prior owner of the generating stations, ComEd (and Generation, through its agreement in the 2001 restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors, including the impact of Midwest Generation's bankruptcy. Additionally, the obligations of EME and Midwest Generation to ComEd under the sale agreement, including the environmental indemnity, may be discharged in the bankruptcy proceeding. In such circumstances, ComEd (and Generation, through ComEd) may only have an unsecured claim against EME and Midwest Generation for the environmental remediation costs that would have otherwise been obligations of EME and Midwest Generation under the sale agreement. This unsecured claim may yield a fractional, or possibly no, recovery for ComEd and Generation.

ComEd and Generation continue to monitor the bankruptcy proceedings and available public information as to potential environmental exposures regarding the Midwest Generation plant sites. Midwest Generation publicly disclosed in its third quarter 2012 Form 10-Q that (i) it has accrued a probable amount of approximately $9 million for estimated environmental investigation and remediation costs under CERCLA, or similar laws, for the investigation and remediation of contaminated property at four Midwest Generation plant sites, (ii) it has identified stations for which a reasonable estimate for investigation and/ or remediation cannot be made and (iii) it and the Illinois EPA entered into Compliance Commitment Agreements outlining specified environmental remediation measures and groundwater monitoring activities to be undertaken at its Powerton, Joliet, Will County and Waukegan generating stations. At this time, however, ComEd and Generation do not have sufficient information to reasonably assess the potential likelihood or magnitude of any such exposures. Further, Midwest Generation's reorganization process will likely extend beyond one year and the outcome is uncertain, including whether the facilities will continue to operate and the identity or financial wherewithal of potential future plant owners. For these reasons, ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations, and no liability has been recorded at December 31, 2012. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. The current estimated cost of the anticipated landfill cover remediation for the site is approximately $42 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the SFS that could take up to one year to complete, and it is unknown when the U.S. EPA will propose a remedy for public comment. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRP's to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately $90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2013 so that settlement discussions could proceed. Based on Exelon's preliminary review, it appears probable that Exelon has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the "Exelon defendants"). The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which was subsequently granted. On October 23, 2012, a third lawsuit was filed in the same court on behalf of three additional plaintiffs against Cotter and seven other defendants, but not Exelon. The allegations in that complaint mirror the two previously-filed lawsuits. It is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. Due to the early stage of the litigation, Exelon cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The potentially responsible parties submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of $50 million to $64 million. The U.S. EPA is expected to make a final selection of one of the alternatives in 2013. Based on Exelon's preliminary review, it appears probable that Exelon has liability and has established an appropriate accrual for its share of the estimated clean-up costs. BGE is indemnified by a wholly owned subsidiary of Generation for most of the costs related to this settlement and clean-up of the site.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, MD. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. The letter provided 60 days for the PRPs to decide whether or not to participate in the investigation. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On July 30, 2012, BGE along with the three other named PRP's provided the U.S. EPA with a "Good Faith Offer" along with a proposed Settlement Agreement to conduct a Remedial Investigation and a Feasibility Study at the Site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The PRPs will seek to reach agreement with the U.S. EPA to conduct the investigation. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the Federal, regional and state levels. In 2007, the U.S. Supreme Court ruled that GHG emissions are pollutants subject to regulation under the new motor vehicle provisions of the Clean Air Act. Consequently, on December 7, 2009, the U.S. EPA issued an endangerment finding under Section 202 of the Clean Air Act regarding GHGs from new motor vehicles and on April 1, 2010 issued final regulations limiting GHG emissions from cars and light trucks effective on January 2, 2011. While such regulations do not specifically address stationary sources, such as a generating plant, it is the U.S. EPA's position that the regulation of GHGs under the mobile source provisions of the Clean Air Act has triggered the permitting requirements under the Prevention of Significant Deterioration (PSD) and Title V operating permit sections of the Clean Air Act for new and modified stationary sources effective January 2, 2011. Therefore, on May 13, 2010, the U.S. EPA issued final regulations (the Tailoring Rule) relating to these provisions of the Clean Air Act for major stationary sources of GHG emissions that apply to new sources that emit greater than 100,000 tons per year, on a CO_2 equivalent basis, and to modifications to existing sources that result in emissions increases greater than 75,000 tons per year on a CO_2 equivalent basis. These thresholds became effective January 2, 2011, apply for six years and will be reviewed by the U.S. EPA for future applicability thereafter. On July 2, 2012, the U.S. EPA declined to lower GHG permit thresholds in its final "Step 3" Tailoring Rule update. The U.S. EPA will review permit thresholds again in a 2015 rulemaking process. On June 26, 2012, the United States Court of Appeals for the District of Columbia, in a *per curium* decision, dismissed industry and state petitions challenging the U.S. EPA's Tailoring Rule based on petitioners' lack of standing. Further, in the same decision, the court denied all challenges to the U.S. EPA's endangerment finding, and the Agency's "Tailpipe Rule" for cars and light trucks. In August 2012, several industry parties filed petitions for an en banc rehearing of the Agency's GHG regulations with the D.C. Circuit court. On September 6, 2012, the Circuit Court ordered the U.S. EPA, intervening groups, and some states to reply to the industry petitions.

On April 13, 2012, the U.S. EPA published proposed regulations for NSPS for GHG emissions from new fossil fuel power plants, greater than 25 MW, that would require the plants to limit CO_2 emissions to a thirty year average of less than 1,000 pounds per MWh (less than 1,800 pounds per MWh for the first ten years and less than 600 pounds per MWh thereafter). Under the PSD regulations, new and modified major stationary sources could be required to install best available control technology, to be determined on a case by case basis. Generation could be significantly affected by the regulations if it were to build new plants or modify existing plants. The U.S. EPA is also expected to establish in 2013 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act.

Litigation and Regulatory Matters

Asbestos Personal Injury Claims

Exelon and Generation. Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At December 31, 2012 and 2011, Generation had reserved approximately $63 million and $49 million, respectively, in total for asbestos-related bodily injury claims. As of December 31, 2012, approximately $14 million of this amount related to 170 open claims presented to Generation, while the remaining $49 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050 based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2012, Generation increased its reserve by approximately $19 million, primarily due to increased actual and projected number and severity of claims. During 2011 and 2010, the updates to this reserve did not result in material adjustments.

BGE. Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of “premises liability,” alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 480 individuals who were never employees of BGE or Generation have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and Generation in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or Generation and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation’s financial results.

Discovery begins in these cases once they are placed on the trial docket. At present, none of the pending cases are set for trial. Given the limited discovery, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs’ employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

Federal Energy Regulatory Commission Investigation

On January 30, 2012, FERC published a notice on its website regarding a non-public investigation of certain of Constellation’s power trading activities in and around the ISO-NY from September 2007 through December 2008. Prior to the merger, Constellation announced on March 9, 2012, that it had resolved the FERC investigation. Under the settlement, Constellation agreed to pay a $135 million civil penalty and $110 million in disgorgement. The disgorgement amount will be disbursed in two ways. First, Constellation will provide $1 million each to six U.S. regional grid operators for the purpose of improving their surveillance and analytic capabilities. The remainder of the disgorgement amount was deposited in a fund that will be administered by a FERC ALJ. State agencies in New York, New England and PJM (the regional grid operator for 13 states and the District of Columbia) will be eligible to make claims against the fund on behalf of electric energy consumers in those states.

During the year ended December 31, 2012, Generation recorded expense of $195 million in operating and maintenance expense with the remaining $50 million recorded as a Constellation pre-acquisition contingency. As of December 31, 2012, the full amount of the civil penalty and disgorgement was paid. See Note 4—Merger and Acquisitions for additional information on the merger.

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.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). The ICC is currently conducting a proceeding to assess ComEd's request. In the absence of a favorable determination from the ICC, some ComEd customers affected by the outages could seek recovery of their actual, non-consequential damages, and the local governments in the areas in which those customers are located could seek recovery of emergency and contingency expenses.

On January 25, 2013 the ALJ issued a Proposed Order in the Summer 2011 Storm Docket. The ALJ found that a complete waiver of liability should apply for five of the six storms at issue, and found that for the July 2011 storm, 34,599 interruptions were preventable and therefore no waiver should apply. The ALJ also found that ComEd's system is designed, constructed and maintained in accordance with good utility practice, thereby rejecting a request by the Illinois Attorney General for the ICC to open an investigation.

In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket). On January 10, 2013, the ALJ issued a Proposed Order in the February 2011 Blizzard Docket, finding that a complete waiver of liability should apply for the storm. As with the Summer 2011 Storm Docket, the ALJ found that ComEd's system is designed, constructed and maintained in accordance with good utility practice.

The ultimate outcomes of these proceedings are uncertain, and the amount of damages, if any, which might be asserted, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

Securities Class Action

Three federal securities class action lawsuits were filed in the United States District Courts for the Southern District of New York and the District of Maryland between September 2008 and November 2008 against Constellation. The cases were filed on behalf of a proposed class of persons who acquired publicly traded securities, including the Series A Junior Subordinated Debentures (Debentures), of Constellation between January 30, 2008 and September 16, 2008, and who acquired Debentures in an offering completed in June 2008. The securities class actions generally allege that Constellation, a number of its former officers or directors, and the underwriters violated the securities laws by issuing a false and misleading registration statement and prospectus in connection with Constellation's June 27, 2008 offering of the Debentures. The securities class actions also allege that Constellation issued false or misleading statements or was aware of material undisclosed information which contradicted public statements, including in connection with its announcements of financial results for 2007, the fourth quarter of 2007, the first quarter of 2008 and the second quarter of 2008 and the filing of its first quarter 2008 Form 10-Q. The securities class actions seek, among other things, certification of the cases as class actions, compensatory damages, reasonable costs and expenses, including counsel fees, and rescission damages.

The Southern District of New York granted the defendants' motion to transfer the two securities class actions filed in Maryland to the District of Maryland, and the actions have since been transferred for coordination with the securities class action filed there. On June 18, 2009, the court appointed a lead plaintiff, who filed a consolidated amended complaint on September 17, 2009. On November 17, 2009, the defendants moved to dismiss the consolidated amended complaint in its entirety. On August 13, 2010, the District Court of Maryland issued a ruling on the motion to dismiss, holding that the plaintiffs failed to state a claim with respect to the claims of the common shareholders under the Securities Exchange Act of 1934 and limiting the suit to those persons who purchased Debentures in the June 2008 offering. In August 2011, plaintiffs requested permission from the court to file a third amended complaint in an effort to attempt to revive the claims of the common shareholders. Constellation filed an objection to the plaintiffs' request for permission to file a third amended complaint and, on March 28, 2012, the District Court of Maryland denied the plaintiffs' request for permission to revive the claims of the common shareholders. Given that limited discovery has occurred, that the court has not certified any class and the plaintiffs have not quantified their potential damage claims, Exelon is unable at this time to provide an estimate of the range of reasonably possible loss relating to these proceedings or to determine the ultimate outcome of the securities class actions or their possible effect on its financial results.

Fund Transfer Restrictions

Under applicable law, Exelon may borrow or receive an extension of credit from its subsidiaries. Under the terms of Exelon's intercompany money pool agreement, Exelon can lend to, but not borrow from the money pool.

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

Under Illinois law, ComEd may not pay any dividend on its stock unless, among other things, "[its] earnings and earned surplus are sufficient to declare and pay same after provision is made for reasonable and proper reserves," or unless it has specific authorization from the ICC. ComEd has also agreed in connection with financings arranged through ComEd Financing III that it will not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debt securities issued to ComEd Financing III; (2) it defaults on its guarantee of the payment of distributions on the preferred trust securities of ComEd Financing III; or (3) an event of default occurs under the Indenture under which the subordinated debt securities are issued.

PECO's Articles of Incorporation prohibit payment of any dividend on, or other distribution to the holders of, common stock if, after giving effect thereto, the capital of PECO represented by its common stock together with its retained earnings is, in the aggregate, less than the involuntary liquidating value of its then outstanding preferred securities. At December 31, 2012, such capital was $3.0 billion and amounted to about 34 times the liquidating value of the outstanding preferred securities of $87 million. Additionally, PECO may not declare dividends on any shares of its capital stock in the event that: (1) it exercises its right to extend the interest payment periods on the subordinated debentures, which were issued to PEC L.P. or PECO Trust IV; (2) it defaults on its guarantee of the payment of distributions on the Series D Preferred Securities of PEC L.P. or the preferred trust securities of PECO Trust IV; or (3) an event of default occurs under the Indenture under which the subordinated debentures are issued.

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

General

Exelon is involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Exelon maintains accruals for such losses that are probable of being incurred and subject to reasonable estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

Income Taxes

See Note 12—Income Taxes for information regarding Exelon's income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

20. Supplemental Financial Information

Supplemental Statement of Operations Information

The following tables provide additional information about Exelon's Consolidated Statements of Operations for the years ended December 31, 2012, 2011 and 2010.

	For the Year Ended December 31,		
	2012	**2011**	**2010**
Taxes other than income			
Utility [a]	$ 463	$443	$476
Property	227	177	175
Payroll	131	123	121
Other	198	42	36
Total taxes other than income	$1,019	$785	$808

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's, PECO's and BGE's utility taxes represent municipal and state utility taxes and gross receipts taxes related to their operating revenues, respectively. The offsetting collection of utility taxes from customers is recorded in revenues on Exelon's Consolidated Statements of Operations.

For the Year Ended December 31, 2012	
Other, Net	
Decommissioning-related activities:	
Net realized income on decommissioning trust funds [a]—	
Regulatory Agreement Units	$ 189
Non-Regulatory Agreement Units	102
Net unrealized gains on decommissioning trust funds—	
Regulatory Agreement Units	386
Non-Regulatory Agreement Units	105
Net unrealized gains on pledged assets—	
Zion Station decommissioning	73
Regulatory offset to decommissioning trust fund-related activities [b]	(530)
Total decommissioning-related activities	325
Investment income [c]	20
Long-term lease income	29
Interest income related to uncertain income tax positions	15
AFUDC-Equity	17
Credit facility termination fees	(85)
Other	25
Other, net	$ 346

For the Year Ended December 31, 2011

Other, Net	
Decommissioning-related activities:	
Net realized income on decommissioning trust funds [(a)]—	
Regulatory Agreement Units	$ 177
Non-Regulatory Agreement Units	45
Net unrealized losses on decommissioning trust funds—	
Regulatory Agreement Units	(74)
Non-Regulatory Agreement Units	(4)
Net unrealized gains on pledged assets—	
Zion Station decommissioning	48
Regulatory offset to decommissioning trust fund-related activities [(b)]	(130)
Total decommissioning-related activities	62
Investment income	10
Long-term lease income	28
Interest income related to uncertain income tax positions	53
AFUDC-Equity	17
Bargain purchase gain related to Wolf Hollow acquisition	36
Other	(3)
Other, net	$ 203

For the Year Ended December 31, 2010

Other, Net	
Decommissioning-related activities:	
Net realized income on decommissioning trust funds [(a)]—	
Regulatory Agreement Units	$ 176
Non-Regulatory Agreement Units	51
Net unrealized gains on decommissioning trust funds—	
Regulatory Agreement Units	316
Non-Regulatory Agreement Units	104
Regulatory offset to decommissioning trust fund-related activities [(b)]	(394)
Total decommissioning-related activities	253
Investment income	1
Long-term lease income	27
Interest income related to uncertain income tax positions	—
AFUDC-Equity	11
Realized gain on Rabbi trust investments	1
Other	19
Other, net	$ 312

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.
(c) Includes the cash return on BGE's rate stabilization deferral. See Note 3—Regulatory Matters for additional information regarding the rate stabilization deferral.

Supplemental Cash Flow Information

The following tables provide additional information regarding Exelon's Consolidated Statements of Cash Flows for the years ended December 31, 2012, 2011 and 2010.

For the Year Ended December 31, 2012

Depreciation, amortization and accretion	
Property, plant and equipment	$1,712
Regulatory assets	129
Amortization of intangible assets, net	40
Amortization of energy contract assets and liabilities [(a)]	1,110
Nuclear fuel [(a)]	848
ARO accretion [(b)]	240
Total depreciation, amortization and accretion	$4,079

For the Year Ended December 31, 2011

Depreciation, amortization and accretion	
Property, plant and equipment	$1,284
Regulatory assets	63
Nuclear fuel [(a)]	755
ARO accretion [(b)]	214
Total depreciation, amortization and accretion	$2,316

For the Year Ended December 31, 2010

Depreciation, amortization and accretion	
Property, plant and equipment	$1,144
Regulatory assets [(c)]	931
Nuclear fuel [(a)]	672
ARO accretion [(b)]	196
Total depreciation, amortization and accretion	$2,943

(a) Included in revenues or fuel expense on Exelon's Consolidated Statements of Operations.
(b) Included in operating and maintenance expense on Exelon's Consolidated Statements of Operations.
(c) Primarily reflects CTC amortization at PECO.

For the Year Ended December 31, 2012

Cash paid (refunded) during the year:	
Interest (net of amount capitalized)	$ 761
Income taxes (net of refunds)	(171)
Other non-cash operating activities:	
Pension and non-pension postretirement benefit costs	$ 820
Loss in equity method investments	91
Provision for uncollectible accounts	164
Provision for obsolete inventory	6
Stock-based compensation costs	94
Other decommissioning-related activity [(a)]	(145)
Energy-related options [(b)]	160
Amortization of regulatory asset related to debt costs	18
Amortization of rate stabilization deferral	57
Amortization of debt fair value adjustment	(34)
Merger-related commitments [(d)]	141
Severance cost	99
Discrete impacts from Energy Infrastructure Modernization Act (EIMA) [(c)]	(96)
Amortization of debt costs	19
Other	(11)
Total other non-cash operating activities	$1,383
Changes in other assets and liabilities:	
Under/over-recovered energy and transmission costs	$ 71
Other regulatory assets and liabilities	(404)
Other current assets	213
Other noncurrent assets and liabilities	(248)
Total changes in other assets and liabilities	$ (368)

Non-cash investing and financing activities:

Change in ARC	$ 781
Change in capital expenditures not paid [e]	160
Merger with Constellation, common stock issued	7,365

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(c) Includes the regulatory asset, pursuant to EIMA, which represents the ICC's approved distribution formula and associated rulings as of December 31, 2012 and ComEd's best estimate of the probable increase in distribution rates to provide recovery of prudent and reasonable costs incurred for the 12 months ended December 31, 2012.

(d) See Note 4—Mergers and Acquisitions for more information on merger-related commitments.

(e) Includes $247 million of capital expenditures not paid as of December 31, 2012 related to Antelope Valley.

For the Year Ended December 31, 2011

Cash paid (refunded) during the year:

Interest (net of amount capitalized)	$ 649
Income taxes (net of refunds)	(457)

Other non-cash operating activities:

Pension and non-pension postretirement benefit costs	$ 542
Provision for uncollectible accounts	121
Stock-based compensation costs	67
Other decommissioning-related activity [a]	16
Energy-related options [b]	137
Amortization of regulatory asset related to debt costs	21
Amortization of rate stabilization deferral	—
Deferral of storm costs	—
Uncollectible accounts recovery, net	14
Discrete impacts from 2010 Rate Case order [c]	(32)
Bargain purchase gain related to Wolf Hollow Acquisition	(36)
Discrete impacts from Energy Infrastructure Modernization Act (EIMA) [d]	(82)
Other	2
Total other non-cash operating activities	$ 770

Changes in other assets and liabilities:

Under/over-recovered energy and transmission costs	$ (45)
Other regulatory assets and liabilities	—
Other current assets	(101)
Other noncurrent assets and liabilities	122
Total changes in other assets and liabilities	$ (24)

Non-cash investing and financing activities:

Change in ARC	$186
Change in capital expenditures not paid [e]	96

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(b) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(c) In May 2011, as a result of the 2010 Rate Case order, ComEd recorded one-time benefits to reestablish previously expensed plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan. See Note 3—Regulatory Matters for more information.

(d) Includes the establishment of a regulatory asset, pursuant to EIMA, for the 2011 annual reconciliation in ComEd's distribution formula rate tariff and the deferral of costs associated with significant 2011 storms, partially offset by an accrual to fund a new Science and Technology Innovation Trust. See Note 3—Regulatory Matters for more information.

(e) Includes $120 million of capital expenditures not paid as of December 31, 2011 related to Antelope Valley.

For the Year Ended December 31, 2010	
Cash paid (refunded) during the year:	
Interest (net of amount capitalized) [(a)]	$ 665
Income taxes (net of refunds)	1,219
Other non-cash operating activities:	
Pension and non-pension postretirement benefit costs	$ 581
Provision for uncollectible accounts	108
Provision for obsolete inventory	12
Stock-based compensation costs	44
Other decommissioning-related activity [(b)]	(91)
Energy-related options [(c)]	(73)
ARO adjustment	(19)
Amortization of regulatory asset related to debt costs	24
Amortization of rate stabilization deferral	—
Accrual for Illinois utility distribution tax refund [(d)]	(25)
Under-recovered uncollectible accounts, net [(e)]	(14)
ARP SO2 allowances impairment	57
Other	5
Total other non-cash operating activities	$ 609
Changes in other assets and liabilities:	
Under/over-recovered energy and transmission costs	$ 61
Other regulatory assets and liabilities	—
Other current assets	(18)
Other noncurrent assets and liabilities [(f)]	(99)
Total changes in other assets and liabilities	$ (56)
Non-cash investing and financing activities:	
Change in ARC	$ (428)
Change in capital expenditures not paid	34
Purchase accounting adjustments	9
Exelon Wind acquisition [(g)]	32

(a) Excludes $167 million of interest paid to the IRS relating to a preliminary agreement reached during the third quarter of 2010. See Note 12—Income Taxes for addition information.

(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 13—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

(c) Includes amounts reclassified to realized at settlement of contracts recorded to results of operations related to option premiums due to the settlement of underlying transactions.

(d) During the second quarter of 2010, ComEd recorded a reduction of $25 million to taxes other than income to reflect management's estimate of future refunds for the 2008 and 2009 tax years associated with Illinois' utility distribution tax based on an analysis of past refunds and interpretations of the Illinois Public Utility Act. Historically, ComEd has recorded refunds of the Illinois utility distribution tax when received. ComEd believes it now has sufficient, reliable evidence to record and support an estimated receivable associated with the anticipated refund for the 2008 and 2009 tax years.

(e) Includes $70 million of under-recovered uncollectible accounts expense from 2008 and 2009 recorded in the first quarter of 2010 as well as $59 million of amortization of the associated regulatory asset. This amount also includes a credit of $3 million of under collections associated with 2010 activity. ComEd is recovering these costs through a rider mechanism authorized by the ICC. See Note 3—Regulatory Matters for additional information regarding the Illinois legislation for recovery of uncollectible accounts.

(f) Primarily relates to a decrease in interest payable at ComEd associated with a change in uncertain income tax positions. See Note 12—Income Taxes for additional information.

(g) Represents contingent liability recorded in connection with the December 9, 2010 acquisition of Exelon Wind. See Note 4—Acquisition for additional information.

DOE Smart Grid Investment Grant. For the year ended December 31, 2012, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $103 million, $56 million and $47 million, respectively, and reimbursements of $113 million, $66 million and $47 million, respectively, related to PECO's and BGE's DOE SGIG programs. For the year ended December 31, 2011, Exelon, PECO and BGE have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $51 million, $51 million and $23 million, respectively, and reimbursements of $56 million, $56 million and $41 million, respectively, related to PECO's and BGE's DOE SGIG programs. See Note 3 - Regulatory Matters for additional information regarding the DOE SGIG.

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of Exelon at December 31, 2012 and 2011.

December 31, 2012	
Investments	
Equity method investments:	
Financing trusts [(a)]	$ 22
Keystone Fuels, LLC	38
Conemaugh Fuels, LLC	26
CENG	1,849
Safe Harbor	293
Malacha	8
Other investments	34
Total equity method investments	2,270
Other investments:	
Net investment in direct financing leases	685
Employee benefit trusts and investments [(b)]	100
Total investments	$3,055

December 31, 2011	
Investments	
Equity method investments:	
Financing trusts [(a)]	$ 15
Keystone Fuels, LLC	13
Conemaugh Fuels, LLC	16
Sacramento Solar	1
Total equity method investments	45
Other investments:	
Net investment in direct financing leases	656
Employee benefit trusts and investments [(b)]	65
Total investments	$ 766

(a) Includes investments in financing trusts, which were not consolidated within the financial statements of Exelon and are shown as investments in affiliates on the Consolidated Balance Sheets. See Note 1—Significant Accounting Policies for additional information.

(b) Exelon's investments in these marketable securities are recorded at fair market value.

December 2010 IRS Payment. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. In order to stop additional interest from accruing on the expected assessment resulting from the agreement, Exelon paid $302 million to the IRS on December 28, 2010. As of December 31, 2010, Exelon had not funded the specific bank account from which the IRS payment was disbursed resulting in a current liability. This amount was subsequently funded in January 2011. Under the authoritative guidance for offsetting balances, Exelon included this payment in Cash and cash equivalents with an offsetting amount in Other current liabilities on its Consolidated Balance Sheets. See Note 12—Income Taxes for additional information.

Like-Kind Exchange Transaction. Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in passive generating station leases with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to require the lessees to return the leasehold interests or to arrange a service contract with a third party for a period following the lease term. If Exelon chooses the service contract option, the leasehold interests will be returned to Exelon at the end of the term of the service contract. In any event, Exelon will be subject to residual value risk if the lessees do not exercise the fixed purchase options. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases. At December 31, 2012 and 2011, the components of the net investment in long-term leases were as follows:

	December 31, 2012	December 31, 2011
Estimated residual value of leased assets	$1,492	$1,492
Less: unearned income	807	836
Net investment in long-term leases	$ 685	$ 656

The following tables provide additional information about liabilities of Exelon at December 31, 2012 and 2011.

	December 31, 2012	December 31, 2011
Accrued expenses		
Compensation-related accruals [(a)]	$ 708	$ 520
Taxes accrued	353	297
Interest accrued	236	192
Severance accrued	91	15
Other accrued expenses [(b)]	412	231
Total accrued expenses	$1,800	$1,255

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $327 million and $184 million for amounts accrued related to Antelope Valley as of December 31, 2012 and December 31, 2011, respectively.

Accumulated Other Comprehensive Income (Loss)

The following tables provide information about accumulated OCI income (loss) recorded (after tax) within Exelon's Consolidated Balance Sheets at December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
Accumulated other comprehensive income (loss)		
Net unrealized gain on cash flow hedges	$ 367	$ 488
Pension and non-pension postretirement benefit plans	(3,155)	(2,938)
Unrealized loss on marketable securities	21	—
Total accumulated other comprehensive income (loss)	$(2,767)	$(2,450)

21. Segment Information

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other regions not considered individually significant referred to collectively as "Other Regions"; including the South, West and Canada. Generation's expanded number of reportable segments is the result of the acquisition of Constellation on March 12, 2012. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd, PECO and BGE based on net income.

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

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

- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Indiana, Ohio, Michigan, Kentucky and Tennessee, and the entire United States footprint of MISO, which covers all or most of North Dakota, South Dakota, Nebraska, Minnesota, Iowa, Wisconsin, the remaining parts of Illinois, Indiana, Michigan and Ohio not covered by PJM, and parts of Montana, Missouri and Kentucky.
- New England represents the operations within ISO-NE covering the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont.
- New York represents operations within ISO-NY, which covers the state of New York in its entirety.
- ERCOT represents operations within Electric Reliability Council of Texas, covering most of the state of Texas.
- Other Regions not considered individually significant:
  - South represents operations in the FRCC and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes the AESO, OIESO and the Canadian portion of MISO.

Exelon and Generation evaluate the performance of Generation's power marketing activities based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for our own generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, upstream natural gas, proprietary trading, energy efficiency and demand response, the design, construction, and operation of renewable energy, heating, cooling, and cogeneration facilities, and home improvements, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, and indoor quality systems, are not allocated to regions. Further, Generation's compensation under the reliability-must-run rate schedule, results of operations from the Brandon Shores, Wagner, and C.P. Crane Maryland generating stations, and other miscellaneous revenues, mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value as a result of the merger are also not allocated to a region.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the years ended December 31, 2012, 2011 and 2010 is as follows:

	Generation [a]	ComEd	PECO	BGE [b]	Other [c]	Intersegment Eliminations	Exelon
Operating revenues [d]:							
2012	$14,437	$ 5,443	$3,186	$2,091	$ 1,396	$ (3,064)	$23,489
2011	10,447	6,056	3,720	—	830	(1,990)	19,063
2010	10,025	6,204	5,519	—	755	(3,859)	18,644
Intersegment revenues [e]:							
2012	$ 1,702	$ 2	$ 3	$ 9	$ 1,381	$ (3,042)	$ 55
2011	1,161	2	5	—	831	(1,990)	9
2010	3,102	2	5	—	756	(3,859)	6
Depreciation and amortization							
2012	$ 768	$ 610	$ 217	$ 238	$ 46	$ 2	$ 1,881
2011	570	554	202	—	21	—	1,347
2010	474	516	1,060	—	25	—	2,075
Operating expenses [d]:							
2012	$13,226	$ 4,557	$2,563	$2,053	$ 1,662	$ (3,043)	$21,018
2011	7,571	5,074	3,065	—	863	(1,990)	14,583
2010	6,979	5,148	4,858	—	792	(3,859)	13,918
Equity in earnings (losses) of unconsolidated affiliates							
2012	$ (91)	$ —	$ —	$ —	$ —	$ —	$ (91)
2011	(1)	—	—	—	—	—	(1)
2010	—	—	—	—	—	—	—
Interest expense, net:							
2012	$ 301	$ 307	$ 123	$ 111	$ 86	$ —	$ 928
2011	170	345	134	—	77	—	726
2010	153	386	193	—	85	—	817
Income (loss) before income taxes:							
2012	$ 1,058	$ 618	$ 508	$ (54)	$ (276)	$ (56)	$ 1,798
2011	2,827	666	535	—	(59)	(13)	3,956
2010	3,150	694	476	—	(91)	(8)	4,221
Income taxes:							
2012	$ 500	$ 239	$ 127	$ (23)	$ (215)	$ (1)	$ 627
2011	1,056	250	146	—	9	(4)	1,457
2010	1,178	357	152	—	(27)	(2)	1,658
Net income (loss):							
2012	$ 558	$ 379	$ 381	$ (31)	$ (61)	$ (55)	$ 1,171
2011	1,771	416	389	—	(68)	(9)	2,499
2010	1,972	337	324	—	(64)	(6)	2,563
Capital expenditures:							
2012	$ 3,554	$ 1,246	$ 422	$ 500	$ 67	$ —	$ 5,789
2011	2,491	1,028	481	—	42	—	4,042
2010	1,883	962	545	—	14	(78)[f]	3,326
Total assets:							
2012	$40,681	$22,905	$9,353	$7,499	$10,432	$(12,316)	$78,554
2011	27,433	22,638	9,156	—	6,147	(10,379)	54,995

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Regions. Intersegment revenues for Generation for the year ended December 31, 2012 include revenue from sales to PECO of $543 million and sales to BGE of $322 million in the Mid-Atlantic region, and sales to ComEd of $795 million in the Midwest region, net of $7 million related to the unrealized mark-to-market losses related to the ComEd swap, which eliminate upon consolidation. For the years ended December 31, 2011 and 2010 intersegment revenues for Generation include revenue from sales to PECO of $508 million and $2,092 million, respectively, in the Mid-Atlantic region, and sales to ComEd of $653 million and $1,010 million, respectively, in the Midwest region.

(b) Amounts represent activity recorded at BGE from March 12, 2012, the closing date of the merger, through December 31, 2012.

(c) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(d) For the years ended December 31, 2012, 2011 and 2010, utility taxes of $82 million, $27 million and $0 million, respectively, are included in revenues and expenses for Generation. For the years ended December 31, 2012, 2011 and 2010, utility taxes of $239 million, $243 million and $205 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2012, 2011 and 2010, utility taxes of $141 million, $173 million and $271 million, respectively, are included in revenues and expenses for PECO. For the period of March 12, 2012 through December 31, 2012, utility taxes of $59 million are included in revenues and expenses for BGE.

(e) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3 for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.
(f) Represents capital projects transferred from BSC to Generation, ComEd and PECO. These projects are shown as capital expenditures at Generation, ComEd and PECO and the capital expenditure is eliminated upon consolidation.

Generation total revenues:

	2012			2011			2010		
	Revenues from external customers (a)	Intersegment revenues	Total Revenues	Revenues from external customers (a)	Intersegment revenues	Total Revenues	Revenues from external customers (a)	Intersegment revenues	Total Revenues
Mid-Atlantic	$ 5,082	$(44)	$ 5,038	$ 4,052	$—	$ 4,052	$ 3,232	$—	$ 3,232
Midwest	4,824	24	4,848	5,445	—	5,445	5,762	—	5,762
New England	1,048	45	1,093	11	—	11	14	—	14
New York	582	(25)	557	—	—	—	—	—	—
ERCOT	1,365	2	1,367	575	—	575	543	—	543
Other Regions (b)	755	78	833	201	—	201	149	—	149
Total Revenues for Reportable Segments	$13,656	$ 80	$13,736	$10,284	$—	$10,284	$ 9,700	$—	$ 9,700
Other (c)	781	(80)	701	163	—	163	325	—	325
Total Generation Consolidated Operating Revenues	$14,437	$—	$14,437	$10,447	$—	$10,447	$10,025	$—	$10,025

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions include the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

Generation total revenues net of purchased power and fuel expense:

	2012			2011			2010		
	RNF from external customers (a)	Intersegment RNF	Total RNF	RNF from external customers (a)	Intersegment RNF	Total RNF	RNF from external customers (a)	Intersegment RNF	Total RNF
Mid-Atlantic	$3,477	$(44)	$3,433	$3,350	$—	$3,350	$2,501	$—	$2,501
Midwest	2,974	24	2,998	3,547	—	3,547	4,081	—	4,081
New England	151	45	196	9	—	9	11	—	11
New York	101	(25)	76	—	—	—	—	—	—
ERCOT	403	2	405	84	—	84	(66)	—	(66)
Other Regions (b)	53	78	131	(14)	—	(14)	(65)	—	(65)
Total Revenues net of purchased power and fuel expense for Reportable Segments	$7,159	$ 80	$7,239	$6,976	$—	$6,976	$6,462	$—	$6,462
Other (c)	217	(80)	137	(118)	—	(118)	100	—	100
Total Generation Revenues net of purchased power and fuel expense	$7,376	$—	$7,376	$6,858	$—	$6,858	$6,562	$—	$6,562

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other regions includes the South, West and Canada, which are not considered individually significant.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value at the merger date.

22. Related Party Transactions

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31, 2012	2011	2010
Operating revenues from affiliates:			
PECO [(a)]	$ 6	$ 9	$ 6
CENG [(b)]	42	—	—
Total operating revenues from affiliates	$ 48	$ 9	$ 6
Fuel and purchased power from related parties:			
CENG [(c)]	$ 793	$—	$—
Keystone Fuels, LLC	61	68	74
Conemaugh Fuels, LLC	68	69	70
Total fuel purchases from related parties	$ 922	$137	$144
Charitable contribution to Exelon Foundation [(d)]	$ 7	$—	$ 10
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 25	$ 25	$ 25
(Loss) gain in equity method investments:			
CENG equity investment income	$ 73	$—	—
Amortization of basis difference in CENG [(e)]	(172)	—	—
Other	8	(1)	—
Total loss in equity method investments	$ (91)	$ (1)	$—

	December 31, 2012	2011
Investments in affiliates:		
ComEd Financing III	$ 6	$ 6
PECO Energy Capital Corporation	4	4
PECO Trust IV	4	5
BGE Capital Trust II	8	—
Total investments in affiliates	$ 22	$ 15
Receivables from affiliates (current):		
CENG [(b)]	$ 16	$—
Payables to affiliates (current):		
CENG [(c)]	$ 83	$—
ComEd Financing III	4	4
PECO Trust III	1	1
Total payables to affiliates (current)	$ 88	$ 5
Long-term debt to BondCo and other financing trusts (including due within one year):		
ComEd Financing III	$206	$206
PECO Trust III	81	81
PECO Trust IV	103	103
BGE Capital Trust II	258	—
Total long-term debt due to financing trusts	$648	$390

(a) The intersegment profit associated with Generation's sale of AECs to PECO is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. See Note 3—Regulatory Matters for additional information.

(b) Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Under the SSA, BSC provides a variety of support services to CENG. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services.

(c) A subsidiary of Generation has an agreement under which it is purchasing 85-90% of the output of CENG's nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG's nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

(d) Exelon Foundation is a nonconsolidated not-for-profit Illinois corporation. The Exelon Foundation was established in 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon.

(e) As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities impact the earnings of CENG. In future periods, Generation may be eligible for distributions from CENG in excess of its 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. Through purchase accounting, Generation recorded the fair value of expected future distributions. Generation will record these distributions when realized as a reduction in its investment in CENG. Distributions realized in excess of the fair value recorded would be recorded in earnings in the period earned.

23. Quarterly Data (Unaudited)

The data shown below, which may not equal the total for the year due to the effects of rounding and dilution, includes all adjustments that Exelon considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2012	2011	2012	2011	2012	2011
Quarter ended:						
March 31	$4,686	$4,956	$359	$1,202	$200	$668
June 30	5,954	4,496	714	1,034	286	620
September 30	6,565	5,254	603	1,181	296	601
December 31	6,284	4,357	704	1,062	378	606

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2012	2011	2012	2011
Quarter ended:				
March 31	705	662	$0.28	$1.01
June 30	853	663	0.34	0.93
September 30	854	663	0.35	0.91
December 31	854	664	0.44	0.91

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2012	2011	2012	2011
Quarter ended:				
March 31	707	664	$0.28	$1.01
June 30	856	664	0.33	0.93
September 30	857	665	0.35	0.90
December 31	857	666	0.44	0.91

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

	2012				2011			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$37.50	$39.82	$39.37	$43.70	$45.45	$45.27	$42.89	$43.58
Low price	28.40	34.54	36.27	38.31	39.93	39.51	39.53	39.06
Close	29.74	35.58	37.62	39.21	43.37	42.61	42.84	41.24
Dividends	0.525	0.525	0.525	0.525	0.525[a]	0.525	0.525	0.525

(a) The fourth quarter 2011 dividend does not include the first quarter 2012 regular quarterly dividend of $0.525 per share, declared by the Exelon Board of Directors on October 25, 2011. The first quarter 2012 dividend is payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

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