EXELON CORP

10−K

Annual report pursuant to section 13 and 15(d)
Filed on 2/9/2012
Filed Period 12/31/2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10−K

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Fiscal Year Ended December 31, 2011

OR

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

Commission File Number	Exact Name of Registrant as Specified in its Charter; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1−16169	**EXELON CORPORATION** **(a Pennsylvania corporation)** 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680−5379 (312) 394−7398	23−2990190
333−85496	**EXELON GENERATION COMPANY, LLC** **(a Pennsylvania limited liability company)** 300 Exelon Way Kennett Square, Pennsylvania 19348−2473 (610) 765−5959	23−3064219
1−1839	**COMMONWEALTH EDISON COMPANY** **(an Illinois corporation)** 440 South LaSalle Street Chicago, Illinois 60605−1028 (312) 394−4321	36−0938600
000−16844	**PECO ENERGY COMPANY** **(a Pennsylvania corporation)** P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101−8699 (215) 841−4000	23−0970240

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

Title of Each Class	Name of Each Exchange on Which Registered
EXELON CORPORATION:	
Common Stock, without par value	New York and Chicago
PECO ENERGY COMPANY:	
Cumulative Preferred Stock, without par value: $4.68 Series, $4.40 Series, $4.30 Series and $3.80 Series	New York
Trust Receipts of PECO Energy Capital Trust III, each representing a 7.38% Cumulative Preferred Security, Series D, $25 stated value, issued by PECO Energy Capital, L.P. and unconditionally guaranteed by PECO Energy Company	New York

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

COMMONWEALTH EDISON COMPANY:
Common Stock Purchase Warrants, 1971 Warrants and Series B Warrants

Indicate by check mark if the registrant is a well−known seasoned issuer, as defined in Rule 405 of the Securities Act.

Exelon Corporation	Yes ☒	No ☐
Exelon Generation Company, LLC	Yes ☒	No ☐
Commonwealth Edison Company	Yes ☒	No ☐
PECO Energy Company	Yes ☒	No ☐

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

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S−K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10−K or any amendment to this Form 10−K. ☐

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

	Large Accelerated	Accelerated	Non−Accelerated	Small Reporting Company
Exelon Corporation	✓			
Exelon Generation Company, LLC			✓	
Commonwealth Edison Company			✓	
PECO Energy Company			✓	

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

Exelon Corporation	Yes ☐	No ☒
Exelon Generation Company, LLC	Yes ☐	No ☒
Commonwealth Edison Company	Yes ☐	No ☒
PECO Energy Company	Yes ☐	No ☒

The estimated aggregate market value of the voting and non−voting common equity held by nonaffiliates of each registrant as of June 30, 2011, was as follows:

Exelon Corporation Common Stock, without par value	$ 28,372,622,746
Exelon Generation Company, LLC	Not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	No established market
PECO Energy Company Common Stock, without par value	None

The number of shares outstanding of each registrant's common stock as of January 31, 2012 was as follows:

Exelon Corporation Common Stock, without par value	663,640,976
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,529
PECO Energy Company Common Stock, without par value	170,478,507

Documents Incorporated by Reference

Portions of the Exelon Proxy Statement for the 2011 Annual Meeting of Shareholders are incorporated by reference in Part III.

Table of Contents

TABLE OF CONTENTS

Table of Contents

Table of Contents

[Table of Contents](#)

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
BSC	Exelon Business Services Company, LLC
Exelon Corporate	Exelon's holding company
Exelon Transmission Company	Exelon Transmission Company, LLC
Exelon Wind	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
Enterprises	Exelon Enterprises Company, LLC
Ventures	Exelon Ventures Company, LLC
AmerGen	AmerGen Energy Company, 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 and PECO, collectively

Other Terms and Abbreviations

1998 restructuring settlement	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
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 Act	Pennsylvania Alternative Energy Portfolio Standards Act of 2004
AFUDC	Allowance for Funds Used During Construction
ALJ	Administrative Law Judge
AMI	Advanced Metering Infrastructure
ARC	Asset Retirement Cost
ARO	Asset Retirement Obligation
ARP	Title IV Acid Rain Program
ARRA of 2009	American Recovery and Reinvestment Act of 2009
Block contracts	Forward Purchase Energy Block Contracts
CAIR	Clean Air Interstate Rule
CAISO	California ISO
CAMR	Federal Clean Air Mercury Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFL	Compact Fluorescent Light
Clean Air Act	Clean Air Act of 1963, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
Competition Act	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
Constellation	Constellation Energy Group, Inc.
CPI	Consumer Price Index
CSAPR	Cross−State Air Pollution Rule
CTC	Competitive Transition Charge
DOE	United States Department of Energy

Table of Contents

Other Terms and Abbreviations

DOJ	United States Department of Justice
DSP Program	Default Service Provider Program
EE&C	Energy Efficiency and Conservation/Demand Response
EGS	Electric Generation Supplier
EIMA	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
FTC	Federal Trade Commission
GAAP	Generally Accepted Accounting Principles in the United States
GHG	Greenhouse Gas
GRT	Gross Receipts Tax
GSA	Generation Supply Adjustment
GWh	Gigawatt hour
HAP	Hazardous air pollutants
Health Care Reform Acts	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
IBEW	International Brotherhood of Electrical Workers
ICC	Illinois Commerce Commission
ICE	Intercontinental Exchange
IFRS	International Financial Reporting Standards
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.
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
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investor Service
mmcf	Million Cubic Feet
MRV	Market−Related Value
MW	Megawatt
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NAV	Net Asset Value
NDT	Nuclear Decommissioning Trust
NEIL	Nuclear Electric Insurance Limited

[Table of Contents](#)

Other Terms and Abbreviations

NERC	North American Electric Reliability Corporation
NJDEP	New Jersey Department of Environmental Protection
Non−Regulatory Agreements Units	Nuclear generating units or portions thereof whose decommissioning−related activities are not subject to contractual elimination under regulatory accounting
NOV	Notice of Violation
NPDES	National Pollutant Discharge Elimination System
NRC	Nuclear Regulatory Commission
NWPA	Nuclear Waste Policy Act of 1982
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
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
PCCA	Pennsylvania Climate Change Act
PRP	Potentially Responsible Parties
Price−Anderson Act	Price−Anderson Nuclear Industries Indemnity Act of 1957
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning−related activities are subject to contractual elimination under regulatory accounting
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RPM	PJM Reliability Pricing Model
RPS	Renewable Energy Portfolio Standards
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
RTEP	Regional Transmission Expansion Plan
RTO	Regional Transmission Organization
S&P	Standard & Poor’s Ratings Services
SEC	United States Securities and Exchange Commission
SERP	Supplemental Employee Retirement Plan
SFC	Supplier Forward Contract
SGIG	Smart Grid Investment Grant
SILO	Sale−In, Lease−Out
SMP	Smart Meter Program
SNF	Spent Nuclear Fuel
SSCM	Simplified Service Cost Method
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Toxics Rule	U.S. EPA Mercury and Air Toxics Rule
VIE	Variable Interest Entity

FILING FORMAT

This combined Annual Report on Form 10−K is being filed separately by Exelon, Generation, ComEd and PECO. Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

FORWARD−LOOKING STATEMENTS

Certain of the matters discussed in this Report are forward−looking statements, within the meaning of the Private Securities Litigation Reform Act of 1995, that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward−looking statements made by a Registrant include those factors discussed herein, including those factors with respect to such Registrant discussed in (a) ITEM 1A. RISK FACTORS, (b) ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, (c) ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA: Note 18 and (d) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward−looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward−looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

The Exelon corporate governance guidelines and the charters of the standing committees of its Board of Directors, together with the Exelon Code of Business Conduct and additional information regarding Exelon's corporate governance, are 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.

PART I

ITEM 1. BUSINESS

General

Corporate Structure and Business and Other Information

Exelon, incorporated in Pennsylvania in February 1999, is a utility services holding company engaged, through its principal subsidiaries, Generation, in the energy generation business, and ComEd and PECO, 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 business consists of its owned and contracted electric generating facilities, its wholesale energy marketing operations and its competitive retail supply operations. Generation has three reportable segments consisting of the Mid−Atlantic, Midwest, and South and West 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 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.

Operating Segments

See Note 20 of the Combined Notes to Consolidated Financial Statements for additional information on Exelon's operating segments.

Proposed Merger with Constellation Energy Group, Inc.

On April 28, 2011, Exelon and Constellation announced that they signed an agreement and plan of merger to combine the two companies in a stock−for−stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Constellation is a leading competitive supplier of power, natural gas and energy products and services for homes and businesses across the continental United States. It owns a diversified fleet of generating units, totaling approximately 12,000 megawatts of generating capacity, and is a leading advocate for clean, environmentally sustainable energy sources, such as solar power and nuclear energy. Baltimore Gas and Electric Company (BGE), Constellation's regulated utility, delivers electricity and natural gas in central Maryland. The resulting company will retain the Exelon name and be headquartered in Chicago. See Note 3 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 controlled MW. Generation combines its large generation fleet with an experienced wholesale energy marketing operation and a competitive retail supply operation. Generation's presence in well−developed wholesale energy markets, integrated hedging strategy that mitigates the adverse impact of short−term market volatility, and low−cost nuclear generating fleet, which is operated consistently at high capacity factors, position it well to succeed in competitive energy markets.

At December 31, 2011, Generation owned generation resources with an aggregate net capacity of 25,544 MW, including 17,115 MW of nuclear capacity. Generation controlled another 5,025 MW of capacity through long−term contracts.

Generation's wholesale marketing unit, Power Team, utilizes Generation's energy generation portfolio and logistical expertise to ensure delivery of energy to Generation's wholesale customers under long−term and short−term contracts and in spot markets.

Generation's retail business provides retail electric and gas services as an unregulated retail energy supplier in Illinois, Pennsylvania, Michigan and Ohio. Generation's retail business is dependent upon continued deregulation of retail electric and gas markets and Generation's ability to obtain supplies of electricity and gas at competitive prices in the wholesale 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. 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 and Southwest Power Pool, have been approved by FERC as RTOs. These entities are responsible for regional planning, managing transmission congestion, developing larger wholesale markets for energy and capacity, maintaining reliability, market monitoring and the elimination or reduction of redundant transmission charges imposed by multiple transmission providers when wholesale customers take transmission service across several transmission systems.

Generating Resources

At December 31, 2011, the generating resources of Generation consisted of the following:

Type of Capacity	MW
Owned generation assets (a)	
Nuclear	17,115
Fossil	5,890
Hydroelectric/Renewable	2,539
Owned generation assets	25,544
Long−term contracts (b)	5,025
Total generating resources	30,569

(a) See "Fuel" for sources of fuels used in electric generation.
(b) Long−term contracts range in duration up to 21 years.

Generation has three reportable segments, the Mid−Atlantic, Midwest, and South and West, representing the different geographical areas in which Generation's power marketing activities are conducted and where Generation's owned and contracted generating resources are located. Mid−Atlantic represents Generation's operations primarily in Pennsylvania, New Jersey and Maryland (approximately 35% of capacity); Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota (approximately 45% of capacity); and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon (approximately 20% of capacity).

Nuclear Facilities

Generation has ownership interests in eleven nuclear generating stations currently in service, consisting of 19 units with an aggregate of 17,115 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 both 2011 and 2010, electric supply (in GWh) generated from the nuclear generating facilities was 82% of Generation's total electric supply, which also includes fossil, hydroelectric and renewable generation and electric supply purchased for resale. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS for further discussion of Generation's electric supply sources.

Nuclear Operations. Capacity factors, which are significantly affected by the number and duration of refueling and non−refueling outages, can have a significant impact on Generation's results of operations. 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 nuclear plants have historically benefited from minimal environmental impact from operations and a safe operating history.

During 2011 and 2010, the nuclear generating facilities operated by Generation achieved capacity factors of 93.3% and 93.9%, respectively. Generation aggressively 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 short and long−term supply commitments and Power Team 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, 2011, the NRC categorized each unit operated by Generation, with the exception of Byron Unit 2 and Limerick Unit 2, in the Licensee Response Column, which is the highest performance band. The NRC categorized Byron Unit 2 and Limerick Unit 2 in the Regulatory Response Column, which is the second highest performance band. 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 ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS – Executive Overview.

Table of Contents

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. In 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 (b)	1	1987	2026
Dresden	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. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. 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.

Nuclear Uprate Program. Generation has announced a series of planned power uprates across its nuclear fleet that would result in between 1,175 and 1,300 MWs at an overnight cost of approximately $3.30 billion in 2011 dollars. Overnight costs do not include financing costs or cost escalation. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half−century of nuclear power operations. Uprate projects, representing approximately 75% of the planned uprate MWs, are underway at the Limerick, Three Mile Island and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remaining uprate MWs will come from additional projects across Generation's nuclear fleet beginning in 2012 and ending in 2017. At 1,300 nuclear−generated MWs, the uprates would displace 6 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. The amount of expenditures to implement the plan ultimately 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. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through December 31, 2011, Generation has added 240 MWs of nuclear generation through its uprate program.

New Nuclear Site Development. Generation is keeping open the option of a new nuclear plant located in Victoria County in southeast Texas; however, Generation has not made a decision to build a nuclear plant at this time. In response to the overall downturn of the economy and the projection of sustained, low natural gas prices, Exelon revised its new nuclear plant development strategy. Exelon had previously submitted a Combined Construction and Operating License (COL) application to the NRC for the Victoria site. On March 25, 2010, Exelon submitted an application for an Early Site Permit (ESP) application for the site and subsequently withdrew its COL application. The ESP allows Exelon to establish the suitability of the Victoria site, which lessens the amount of work necessary should Exelon later decide to reapply for a COL. Additionally, the ESP accommodates a variety of possible future plant designs, allowing for flexibility in selecting a reactor technology later as part of a COL application. If approved by the NRC, the ESP would effectively reserve the site for 20 years with the possibility of renewal for another 20 years. Any decision to build at the Victoria site would be made based on then−current economics. The original COL project spent the authorized $100 million. The Exelon board authorized an additional $30 million for the ESP project. The total project costs as of December 31, 2011 were $16 million. The current NRC review and approval schedule supports issuance of the ESP in late 2015.

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.

Table of Contents

As of December 31, 2011, Generation had approximately 56,300 SNF assemblies (13,500 tons) stored on site in SNF pools or dry cask storage (this includes SNF at Zion Station, for which Generation retains ownership, see Note 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning). 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. The following table describes the current status of Generation's SNF storage facilities.

Site	Date for loss of full core reserve [(a)]
Braidwood	Dry cask storage in operation
Byron	Dry cask storage in operation
Clinton	2016
Dresden	Dry cask storage in operation
LaSalle	Dry cask storage in operation
Limerick	Dry cask storage in operation
Oyster Creek	Dry cask storage in operation
Peach Bottom	Dry cask storage in operation
Quad Cities	Dry cask storage in operation
Salem	Dry cask storage in operation
Three Mile Island [(b)]	2023

(a) The date for loss of full core reserve identifies when the on−site storage pool will no longer have sufficient space to receive a full complement of fuel from the reactor core. Dry cask storage will be in operation at those sites prior to the closing of their on−site storage pools.
(b) The DOE previously has indicated it will begin accepting spent fuel in 2020. If this does not occur, Three Mile Island will need an onsite dry cask storage facility.

For a discussion of matters associated with Generation's contracts with the DOE for the disposal of SNF, see Note 18 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 approval for its Peach Bottom and LaSalle stations that will allow it to store LLRW from its remaining stations that have 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. 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 18 of the Combined Notes to Consolidated Financial Statements for details.

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

Decommissioning. NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available in specified minimum amounts at the end of the life of the facility to decommission the facility. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview; ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates, Nuclear Decommissioning Asset Retirement Obligations and Nuclear Decommissioning Trust Fund Investments; and Notes 2, 8 and 12 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 was $183 million at December 31, 2011. As of December 31, 2011, NDT funds set aside to pay for these obligations were $351 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 12 of the Combined Notes to Consolidated Financial Statements for additional information regarding Zion Station Decommissioning.

Fossil, Hydroelectric and Renewable Facilities

Generation operates various fossil, hydroelectric and renewable facilities and maintains ownership interests in several other facilities including LaPorte, Keystone, Conemaugh and Wyman, which are operated by third parties. In 2011 and 2010, electric supply (in GWh) generated from owned fossil, hydroelectric and renewable generating facilities was 7% and 6%, respectively, of Generation's total electric supply. The majority of this output was dispatched to support Generation's power marketing activities. For additional information regarding Generation's electric generating facilities, see ITEM 2. PROPERTIES—Generation.

***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. Construction has started, with the first portion of the site expected to come online in late 2012 and full operation planned for late 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 $713 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 $1.36 billion to be accretive to earnings beginning in 2013 and to be accretive to cash flows starting in 2013. The project is expected to have stable earnings and cash flow profiles due to the PPA. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Antelope Valley acquisition.

Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of the equity interest of Wolf Hollow, LLC (Wolf Hollow), a combined−cycle natural gas−fired power plant in north Texas, for a purchase price of $311 million pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. Generation recognized a $42 million gain as part of the transaction. See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Wolf Hollow acquisition.

***Exelon Wind*. In 2010, Generation acquired 735 MWs of installed, operating wind capacity located in eight states for approximately $893 million in cash. On January 1, 2012, Michigan Wind 2, one of the Exelon Wind development projects acquired in 2010, began commercial operations. The facility has a capacity of approximately 90MWs. In addition, Generation is currently developing additional wind projects in Michigan with a combined capacity of approximately 140 MWs. See Note 3 and Note 1 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Exelon Wind acquisition and new site development costs, respectively.

Plant Retirements. On May 31, 2011, Cromby Generating Station (Cromby) Unit 1 and Eddystone Generating Station (Eddystone) Unit 1 were retired; on December 31, 2011, Cromby Unit 2 was retired and Eddystone Unit 2 will retire on May 31, 2012. For more information regarding plant retirements, see Note 14 of the Combined Notes to Consolidated Financial Statements.

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. The license for the Conowingo Hydroelectric Project expires on August 31, 2014 and for the Muddy Run Pumped Storage Facility Project expires on September 1, 2014. In March 2009, Generation filed a Pre−Application Document and Notice of Intent to renew the licenses, pursuant to FERC relicensing requirements. Generation plans to file license applications with FERC for both facilities in August 2012. For those plants located within the control areas administered by PJM, notice is required to be provided before a plant can be retired.

Insurance. Generation maintains business interruption insurance for its wind and solar PV projects, and delay in start−up insurance for its wind and solar PV 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, 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.

Table of Contents

Long−Term Contracts

In addition to energy produced by owned generation assets, Generation sells electricity purchased under the following long−term contracts in effect as of December 31, 2011:

Seller	Location	Expiration	Capacity (MW)
Kincaid Generation, LLC	Kincaid, Illinois	2013	1,108
Tenaska Georgia Partners, L.P. (a)	Franklin, Georgia	2030	945
Tenaska Frontier Partners, Ltd. (b)	Shiro, Texas	2020	830
Green Country Energy, LLC (c)	Jenks, Oklahoma	2022	778
Elwood Energy, LLC	Elwood, Illinois	2012	775
Old Trail Windfarm, LLC	McLean, Illinois	2026	198
Others (d)	Various	2012 to 2028	391
Total			5,025

(a) Generation has sold its rights to 945 MW of capacity, energy and ancillary services supplied from its existing long−term contract with Tenaska Georgia Partners, L.P. through a PPA with Georgia Power, a subsidiary of Southern Company for a 20−year period that began on June 1, 2010.
(b) On December 17, 2009, Generation entered into a PPA with Entergy Texas, Inc. (ETI) to sell 150 MWs through April 30, 2011 and 300 MWs thereafter of capacity and energy from the Frontier Generating Station. The term of the PPA is approximately 10 years.
(c) Commencing June 1, 2012 and lasting for 10 years, Generation has agreed to sell its rights to 520 MW, or approximately two−thirds, of capacity, energy and ancillary services supplied from its existing long−term contract with Green Country Energy, LLC through a PPA with Public Service Company of Oklahoma, a subsidiary of American Electric Power Company, Inc.
(d) Includes long−term capacity contracts with six counterparties.

Fuel

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

	Source of Electric Supply (a)	
	2011	2012 (Est.)
Nuclear	139,297	141,316
Purchases—non−trading portfolio	18,908	18,397
Fossil and renewable	11,638	16,466
Total supply	169,843	176,179

(a) Represents Generation’s proportionate share of the output of its generating plants.

The fuel costs for nuclear generation are substantially less than for fossil−fuel generation. Consequently, nuclear generation is generally the most cost−effective way for Generation to meet its wholesale obligations and some of Generation’s retail business 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 2015. Generation’s contracted conversion services are sufficient to meet all of its uranium conversion requirements through 2015. All of Generation’s enrichment requirements have been contracted through 2017. Contracts for fuel fabrication have been obtained through 2013. 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 annual, monthly and spot−market purchases. Some fossil generation stations can use either oil or natural gas as fuel. Fuel oil inventories are managed so that in the winter months sufficient volumes of fuel are available in the event of extreme weather conditions and during the remaining months to take advantage of favorable market pricing.

Generation uses financial instruments to mitigate price risk associated with certain commodity price exposures. Generation also hedges forward price risk with both over−the−counter and exchange−traded instruments. See ITEM 1A. RISK FACTORS, ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Critical Accounting Policies and Estimates and Note 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding derivative financial instruments.

Power Team

Generation's wholesale marketing and retail electric supplier 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 seeks to maintain a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. 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. Generation enters into PPAs as part of its overall strategic plan, with objectives such as obtaining low−cost energy supply sources to meet its physical delivery obligations to customers and assisting customers to meet renewable portfolio standards. Generation may buy power to meet the energy demand of its customers, including ComEd and PECO. These purchases may be for more than the energy demanded by Power Team's customers. Power Team 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 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, such as a financial swap with ComEd that is described below and runs into 2013. However, except for the ComEd swap arrangement, Generation is exposed to relatively greater commodity price risk beyond 2012 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, 2011, the percentage of expected generation hedged was 88%−91%, 61%−64%, and 32%−35% for 2012, 2013 and 2014, 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 cash flow hedges, other derivatives and certain non−derivative contracts, including sales to ComEd and PECO 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. 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

Table of Contents
management group and Exelon's RMC monitor the financial risks of the power marketing activities. Generation also uses financial and commodity contracts for proprietary trading purposes, but this activity accounts for only a small portion of Generation's efforts.

At December 31, 2011, Generation's short and long−term commitments relating to the sale and purchase of energy and capacity from and to unaffiliated utilities and others were as follows:

(in millions)	Net Capacity Purchases (a)	Power Only Purchases (b)	Power Only Sales	Transmission Rights Purchases (c)
2012	$ 177	$ 11	$ 1,150	$ 9
2013	71	—	834	6
2014	63	—	346	—
2015	61	—	200	—
2016	61	—	177	—
Thereafter	478	—	737	—
Total	$ 911	$ 11	$ 3,444	$ 15

(a) Net capacity purchases include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented as commitments represent Generation's expected payments under these arrangements at December 31, 2011, including certain capacity charges, which are subject to plant availability.
(b) Excludes renewable energy PPA contracts 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.

ComEd procures all of its electricity through a competitive procurement process, through which Generation supplies a portion of ComEd's load. Additionally, in order to fulfill a requirement of the Illinois Settlement, Generation and ComEd entered into a five−year financial swap contract that expires on May 31, 2013. See ComEd – Retail Electric Services, Procurement Related Proceedings for additional information regarding ComEd's procurement−related proceedings and the financial swap contract.

PECO procures all of its electricity through a competitive procurement process, through which Generation will continue to supply a portion of PECO's load. See PECO – Retail Electric Services, Procurement Related Proceedings for additional information regarding PECO's competitive, full−requirements energy−supply procurement process.

Capital Expenditures

Generation's business is capital intensive and requires significant investments in energy generation and in other internal infrastructure projects. Generation's estimated capital expenditures for 2012 are as follows:

(in millions)	
Nuclear fuel (a)	$1,173
Production plant	844
Uprates	450
Renewable energy projects (b)	1,301
Total	$3,768

(a) Includes Generation's share of the investment in nuclear fuel for the co−owned Salem plant.
(b) Includes expenditures for Antelope Valley and Exelon Wind development projects.

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 mandatory reliability standards set by the NERC.

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 3 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 2012 to 2066. ComEd anticipates working with the appropriate agencies to extend or replace the franchise agreements prior to expiration.

ComEd'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. 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 service is regulated, while electric customers are allowed to purchase generation from a competitive electric generation supplier.

At December 31, 2011, approximately 380,300 retail customers representing approximately 56% of ComEd's annual retail kWh sales, had elected to purchase their electricity from a competitive electric generation supplier. Customers who receive electricity from a competitive electric generation supplier continue to pay a delivery charge to ComEd. Under the current regulatory mechanisms in effect, ComEd is permitted to recover its electricity procurement costs from retail customers, without mark−up. Thus, although energy sales affect ComEd's reported revenues, they do not affect its net income, as the energy sales are offset by an equal amount of purchased power expense.

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.

Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process. On October 26, 2011, the Illinois General Assembly overrode the Governor's veto of the Illinois Energy Infrastructure Modernization Act (SB 1652), which became effective immediately. The Illinois General

Assembly also passed House Bill 3036 (the Trailer Bill), which modifies and supplements SB 1652. The Governor signed the Trailer Bill into law on December 30, 2011. The combined legislation (EIMA) provides for substantial capital investment over a ten−year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre−established distribution formula rate tariff. 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. In addition, ComEd will make contributions to fund customer assistance programs and for a new Science and Technology Innovation Trust fund. The legislation also contains a provision for the IPA to conduct procurement events for energy and REC requirements for the June 2013 through December 2017 period. In order to protect consumers, EIMA contains several restrictions and potential criteria for early termination, ending ComEd's investment commitment and the performance−based formula rates.

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The ICC will review ComEd's rate filing to evaluate the prudence and reasonableness of the costs and issue its order in a shortened proceeding. This rate will take effect 30 days after the ICC order, which must be issued by May 31, 2012. See Note 2 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. ComEd and several other parties filed appeals of the rate order with the Illinois Appellate Court (Court). On September 30, 2010, the Court issued a decision in those appeals. That decision ruled against ComEd on the treatment of post−test year accumulated depreciation and the recovery of costs for an AMI/Customer Applications pilot program via a rider (Rider SMP). ComEd's Petition for Leave to Appeal to the Illinois Supreme Court was denied on March 30, 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in early 2012. ComEd filed testimony that no refunds should be required in this proceeding and, in the event of any refund, the maximum refund should be $30 million. On November 10, 2011, the ALJ issued a proposed order in the remand proceeding agreeing with ComEd that the ICC does not have the legal authority to order a refund; a refund may only be ordered by a court. The ALJ also concluded that, to the extent that a court orders a refund, it should be in the amount of $37 million, including interest. As of December 31, 2011, ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to reconciliation when the ICC issues a final order. ComEd does not believe any of its other riders are affected by the Court's ruling.

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 services revenue requirement and a 10.5% rate of return on common equity. 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, 2011. The order has been appealed to the Court by several parties. ComEd cannot predict the results of these appeals. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's electric distribution rate cases.

Procurement−Related 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 on the spot market with a five−year variable−to−fixed financial swap contract with Generation that expires on May 31, 2013. See Notes 2 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding ComEd's procurement−related proceedings and the financial swap contract.

Continuous Power Interruption. Illinois law 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) 30,000 or more 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. ComEd does not believe that during the years 2011, 2010 and 2009 it had any interruptions that have triggered this damage liability or reimbursement requirement.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable under provisions of the Illinois Public Utilities Act that could require damage compensation to customers in connection with the July 11, 2011 storm system that affected more than 900,000 customers in ComEd's service territory, as well as five other storm systems that affected ComEd's customers during June and July 2011. 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 which those customers are located could seek recovery of emergency and contingency expenses. See Note 18 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 and reliability of its system. Based on PJM's RTEP, ComEd has various construction commitments, as discussed in Note 2 of the Combined Notes to Consolidated Financial Statements. ComEd's most recent estimate of capital expenditures for electric plant additions and improvements for 2012 is $1,330 million, which includes RTEP projects and infrastructure modernization resulting from EIMA. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS, Liquidity and Capital Resources for further information.

PECO

PECO is engaged principally in the purchase and regulated retail sale of electricity and the provision of transmission and distribution services to retail customers in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of 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 494,000 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. Under the 1998 restructuring settlement, PECO's electric generation rates were capped through a transition period that ended on December 31, 2010. During the transition period, PECO was authorized to recover from customers $5.3 billion of costs that might not have otherwise been recovered in a competitive market (stranded costs) with a 10.75% return on the unamortized balance through the imposition and collection of a non−bypassable CTC, which was a component of the capped electric generation rate on customer bills. As of December 31, 2010, PECO's stranded costs were fully recovered.

Beginning January 1, 2011, PECO's electric supply procurement cost rates charged to default service customers are subject to adjustments at least quarterly to recover or refund the difference between PECO's actual cost of electricity delivered and the amount included in rates without markup through the GSA.

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, 2011, there were 59 alternative EGSs serving PECO customers. At December 31, 2011, the number of retail customers purchasing energy from an alternative EGS was 387,628, representing approximately 25% of total retail customers. Retail deliveries purchased from EGSs represented approximately 57% of PECO's retail kWh sales for the year ended December 31, 2011. This represents a significant increase from prior years due to the expiration of electric generation rate caps that were lower than market prices during the transition period. 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 selection of an alternative EGS or PECO as default service provider does not impact PECO's results of operations or financial position. PECO's cost of electric supply is passed directly through to default service customers without markup. For those customers that choose an alternative EGS, PECO will act as the billing agent but will not record revenues or expenses 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.

Electric Distribution Rate Case. In December 2010, the PAPUC approved a settlement of PECO's electric distribution rate case filed in August 2010 that provides for an annual revenue increase of $225 million. The approved electric distribution rates became effective on January 1, 2011.

Procurement Proceedings. Prior to January 1, 2011, PECO procured all its electric supply under a full requirements PPA with Generation, which expired on December 31, 2010. The term and procurement costs under the PPA with Generation corresponded with PECO's transition period and capped electric generation rates in accordance with its 1998 restructuring settlement. Beginning January 1, 2011, PECO's electric supply for its customers is procured through contracts executed in accordance with its current PAPUC−approved DSP Program. PECO has entered into contracts with PAPUC−approved bidders as part of its six competitive procurements conducted since June 2009 for its default electric supply beginning January 2011, which included fixed price full requirement contracts for all procurement classes, spot market price full requirements contracts for the commercial and industrial procurement classes, and block energy contracts for the residential procurement class. PECO will conduct three additional competitive procurements for electric supply for all customer classes during the term of its current DSP Program, which expires on May 31, 2013.

On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC, which outlined how PECO will purchase electric supply for default service customers from June 1, 2013 through May 31, 2015. The plan proposed to procure electric supply through a combination of one−year and two−year fixed full requirements contracts, reduce the amount of time between when the energy is purchased and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. The plan also proposed 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. Hearings on the filing will be held in the summer of 2012 with a PAPUC ruling expected in mid−October 2012.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Smart Meter and Energy Efficiency Programs

Smart Meter Programs. In April 2010, the PAPUC approved PECO's $550 million 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. As a result of the SGIG funding, PECO will deploy 600,000 smart meters by 2013, accelerate universal deployment of more than 1.6 million smart meters by 2020 and increase smart grid investments to approximately $100 million through 2013. In total, through 2020, PECO plans to spend up to $650 million on its smart grid and smart meter infrastructure. The SGIG funding will be used to significantly reduce the impact of those investments on PECO customers.

Energy Efficiency Programs. PECO's approved four−year EE&C plan totals approximately $328 million and 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. In July 2011, PECO filed a petition to make adjustments to its EE&C Plan. The filing noted that PECO has exceeded the 1% energy use reduction target required by May 31, 2011 in accordance with Act 129; the adjustments, which were approved by the PAPUC on August 18, 2011, will allow PECO to meet its May 31, 2013 targets for energy use and energy demand reductions, while remaining within its approved plan budget.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Natural Gas

PECO's natural gas sales and distribution service revenues are derived pursuant to 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. In 2011, 40% of PECO's current total yearly throughput was provided by natural gas suppliers other than PECO, of which, 34% was for commercial and industrial customers participating in PECO's High Volume Transportation Program and 6% was for residential and small commercial customers participating in PECO's Low Volume Transportation Choice Program. PECO provides distribution service, billing, metering, installation, maintenance and emergency response services at regulated rates to all customers in PECO's service territory.

Natural Gas Distribution Rate Cases. On January 1, 2009, PECO implemented the natural gas distribution rates approved by the PAPUC in its settlement of the 2008 natural gas distribution rate case that provided for an additional $77 million of revenue annually. In December 2010, the PAPUC approved a settlement of PECO's natural gas distribution rate case filed in August 2010 that provides an increase in annual revenue of $20 million, which became effective in natural gas distribution rates on January 1, 2011.

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 46 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 2011−2012 heating season planned supplies.

See Note 2 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 2 of the Combined Notes to Consolidated Financial Statements. PECO's most recent estimate of capital expenditures for plant additions and improvements for 2012 is $436 million, which includes capital expenditures related to the smart meter program and SGIG project net of DOE expected reimbursements.

ComEd and PECO

Transmission Services

ComEd and PECO provide unbundled transmission service under rates established 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 and PECO, as owners of transmission facilities, are required to provide open access to their transmission facilities under filed tariffs at cost−based rates. ComEd and PECO are required to comply with FERC's Standards of Conduct regulation, as amended, 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 and PECO are members of PJM and provide regional transmission service pursuant to the PJM Tariff. ComEd, PECO 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.

As a result of PECO's 1998 restructuring settlement, retail transmission rates were capped at the level in effect on December 31, 1996, which remained unchanged through December 31, 2010. Beginning January 1, 2011, 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.

See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding transmission services.

Table of Contents

Employees

As of December 31, 2011, Exelon and its subsidiaries had 19,267 employees in the following companies, of which 8,567 or 44% were covered by collective bargaining agreements (CBAs):

	IBEW Local 15 (a)	IBEW Local 614 (b)	Other CBAs (c)	Total Employees Covered by CBAs	Total Employees
Generation	1,697	150	1,813	3,660	9,586
ComEd	3,561	—	—	3,561	5,769
PECO(d)	—	1,237	—	1,237	2,418
Other	82	—	27	109	1,494
Total	5,340	1,387	1,840	8,567	19,267

(a) A separate CBA between ComEd and IBEW Local 15, ratified on November 20, 2009, covers approximately 42 employees in ComEd's System Services Group.
(b) 1,237 PECO craft and call center employees in the Philadelphia service territory are covered by CBAs with IBEW Local 614. The CBAs expire on March 31, 2015. Additionally, Exelon Power, an operating unit of Generation, has an agreement with IBEW Local 614, which expires on March 31, 2015 and covers 150 employees.
(c) During 2009 and early 2010, CBAs were agreed to with the following Security Officers unions: Braidwood, Byron, Clinton, Dresden, Oyster Creek and TMI. The agreements generally expire between 2013 and 2015, except for the agreements at Braidwood, Byron and TMI, which expire in 2012. Additionally, during 2009, a 5−year agreement was reached with Oyster Creek Nuclear Local 1289, which will expire in 2015. In 2010, a 3−year agreement was negotiated with New England ENEH, UWUA Local 369, which will expire in 2014, and covers 10 employees. In 2011, four 3−year agreements were reached at Braidwood, Dresden, LaSalle and Quad Cities.
(d) Other includes shared services employees at BSC.

Environmental Regulation

General

Exelon, Generation, ComEd and PECO are subject to environmental regulation administered by the U.S. EPA and various state and local environmental protection agencies or boards. State and local regulation includes the authority to regulate air, water and noise emissions and solid waste disposals. The Registrants are also subject to legislation regarding environmental matters by the United States Congress and by various state and local jurisdictions where the Registrants operate their facilities.

The Exelon board of directors is responsible for overseeing the management of environmental matters. Exelon has a management team to address environmental matters, including the CEO who also serves as Exelon's Chief Environmental Officer; the Vice President, Corporate Strategy and Exelon 2020; the Corporate Environmental Strategy Director and the Environmental Regulatory Strategy Director, as well as senior management of Generation, ComEd and PECO. Performance for those individuals directly involved in environmental strategy activities 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 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 and PECO.

Water

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. All 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 18 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, as well as the planned cessation of generation operations at Oyster Creek.

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. Government 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. Government 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 and Pennsylvania, have also enacted statutes that contain provisions substantially similar to CERCLA. In addition, the RCRA governs treatment, storage and disposal of solid and hazardous wastes and cleanup of sites where such activities were conducted.

Generation, ComEd and PECO and their subsidiaries are or are likely to become parties to proceedings initiated by the U.S. EPA, state agencies and/or other responsible parties under CERCLA and RCRA with respect to a number of sites, including MGP sites, or may undertake to investigate and remediate sites for which they may be subject to enforcement actions by an agency or third party.

Environmental Remediation

ComEd's and PECO's environmental liabilities primarily arise from contamination at former MGP sites. MGPs manufactured gas in Illinois and Pennsylvania from approximately 1850 to the 1950s. ComEd and PECO generally did not operate MGPs as corporate entities but did acquire MGP sites as part of the absorption of smaller utilities, for which they may be liable for environmental remediation. ComEd, pursuant to an ICC order, and PECO, pursuant to the joint settlements of the 2008 and 2010 natural gas distribution rate cases, are recovering environmental remediation costs of the MGP sites through a provision within customer rates. PECO's 2010 natural gas distribution rate case increased the annual MGP recovery to be collected from customers beginning in January 2011.

The amount to be expended in 2012 at Exelon for compliance with environmental remediation is expected to total $32 million, consisting of $26 million and $6 million at ComEd and PECO, respectively. In addition, Generation, ComEd and PECO may be required to make significant additional expenditures not presently determinable.

Generation's environmental liabilities primarily arise from contamination at current or former generation facilities. As of December 31, 2011, Generation has established an appropriate accrual to comply with environmental remediation requirements which includes an accrual for contamination attributable to low level radioactive residues at a storage and reprocessing facility named Latty Avenue near St. Louis, Missouri formerly owned by Cotter Corporation, a former ComEd subsidiary.

See Notes 2 and 18 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.

Air

Air quality regulations promulgated by the U.S. EPA and the various state and local environmental agencies in Illinois, Massachusetts, Pennsylvania and Texas in accordance with the Federal Clean Air Act and the Clean Air Act Amendments of 1990 (Amendments) 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 Amendments establish a comprehensive and complex national program to substantially reduce air pollution, including a two−phase program to reduce acid rain effects by significantly reducing emissions of SO_2 and NO_x from power plants. Flue−gas desulfurization systems (SO_2 scrubbers) have been installed at all of Generation's owned coal−fired units.

See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding clean air regulation and legislation in the forms of the CSAPR, the regulation of hazardous air pollutants from coal− and oil−fired electric generating facilities under the Mercury and Air Toxics (MATS) rule, and regulation of GHG emissions, in addition to NOVs issued to Generation and ComEd for alleged violations of the Clean Air Act.

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, 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 Generation's combustion of fossil fuels represent approximately 90% of Exelon's total GHG emissions. However, only approximately 5% of Exelon's total electric supply is provided by its fossil fuel generating plants. Other GHG emission sources at Exelon include natural gas (methane) leakage on the gas pipeline system and the coal piles at its generating plants, sulfur hexafluoride (SF_6) leakage in its electric operations and refrigerant leakage from its chilling and cooling equipment as well as fossil fuel combustion in its motor vehicles and usage of electricity in its facilities. Despite its small carbon footprint, 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 international, Federal, regional and state levels.

International Climate Change Regulation. At the international level, the United States is currently not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC) and became effective for signatories on February 16, 2005. The United Nations' Kyoto Protocol process generally requires developed countries to cap GHG emissions at certain levels during the 2008−2012 time period. At the conclusion of the December 2011 United Nations Framework Convention on Climate Change (COP 17) Conference in Durban, South Africa, a package of decisions was adopted that initiate another commitment phase for the Kyoto Protocol and initiating a new round of discussions with the objective of establishing a successor agreement by 2015 that would commence beginning in 2020. These decisions build on the agreements reached in the 2009 Copenhagen Accord, including the United States agreeing to undertake a number of voluntary measures, including the establishment of a goal to reduce GHG emissions and contributions toward a fund to assist developing nations to address their GHG emissions.

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. It is uncertain when any mandatory programs to reduce GHG emissions would be established in the future. If these programs become effective, 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 GHG emissions regulation for new stationary sources through its proposed New Source Performance Standard under the existing provisions of the Clean Air Act. Such proposed regulation has the potential to cause Exelon to incur material costs of compliance for GHG emissions from stationary sources.

Regional and State Climate Change Legislation and Regulation. At a regional level, on November 15, 2007, six Midwest state Governors (Illinois, Iowa, Kansas, Michigan, Minnesota and Wisconsin) signed the Midwestern Greenhouse Gas Accord. Under that Accord, an inter−state work group was formed to establish a Midwestern GHG Reduction Program that will: (1) establish GHG reduction targets and timeframes consistent with member state targets; (2) develop a market−based and multi−sector cap−and−trade program to help achieve GHG reductions; and (3) develop other mechanisms and policies to assist in meeting GHG reduction targets (e.g. a low carbon fuel standard). In May 2010, an advisory group appointed by the Governors issued recommendations, but no actions have been taken on the recommendations.

At the state level, the PCCA was signed into law in Pennsylvania in July 2008. The PCCA requires, among other things, that: a Climate Change Advisory Committee be formed; a report on the potential impact of climate change in Pennsylvania be developed; the PA DEP develop a GHG inventory for Pennsylvania; a voluntary GHG registry be identified; and the PA DEP, in consultation with the Climate Change Advisory Committee, develop a Climate Change Action Plan for Pennsylvania to be reviewed with the Pennsylvania General Assembly. The Climate Change Advisory Committee issued its recommendations for an Action Plan for consideration by the Pennsylvania legislature on October 9, 2009.

Exelon’s Voluntary Climate Change Efforts. In a world increasingly concerned about global climate change, nuclear power as well as other virtually non−GHG emitting power will play a pivotal role. As a result, Exelon’s low−carbon generating fleet is seen by management as a competitive advantage. Exelon believes that the significance of its low GHG emission profile can only grow as policymakers take action to address global climate change.

Despite Exelon’s low GHG emission intensity and the absence of a mandatory national program in the United States, Exelon is actively engaged in voluntary reduction efforts. Exelon made a voluntary commitment in 2005 under the U.S. EPA’s Climate Leaders Program to reduce its GHG emissions by 8% from 2001 levels by the end of 2008. Exelon achieved this goal by reducing its CO_2e emissions to 9.7 million metric tons in 2008, from a 2001 baseline of 15.7 million metric tons. This was accomplished through the retirement of older, inefficient fossil power plants, reduced leakage of SF_6, increased use of renewable energy and energy efficiency initiatives.

In 2008, Exelon expanded its commitment to GHG reduction with the announcement of a comprehensive business and environmental strategic plan. The plan, Exelon 2020, details an enterprise−wide strategy and a wide range of initiatives being pursued by Exelon to reduce Exelon's GHG emissions and those of its customers, communities, suppliers and markets. Exelon 2020 sets a goal for Exelon to reduce, offset, or displace more than 15 million metric tons of GHG emissions per year by 2020 (from 2001 levels).

Through Exelon 2020, Exelon is pursuing three broad strategies: reducing or offsetting its own carbon footprint, helping customers and communities reduce their GHG emissions, and offering more low−carbon electricity in the marketplace. In 2010, Exelon announced that it had achieved just over 50% of the annual Exelon 2020 goal. The retirement of fossil units, Cromby Units 1 and 2 and Eddystone Unit 1 in 2011 and the planned retirement of Eddystone Unit 2 in 2012, will further contribute to fully achieving the goal. The early retirement of Oyster Creek may result in increased generation from fossil generating plants in the PJM RTO, which could result in increased GHG emissions under Exelon 2020 through reverse displacement. The current plan for achieving the Exelon 2020 goal accounts for these events. Initiatives to reduce Exelon's own carbon footprint include reducing building energy consumption by 25%, reducing vehicle fleet emissions, improving the efficiency of the generation and delivery system for electricity and natural gas, and developing an industry−leading green supply chain. Plans to help customers reduce their GHG emissions include ComEd's Smart Ideas portfolio of energy efficiency programs, a similar portfolio of energy efficiency programs at PECO to meet the requirements of Act 129, the implementation of smart−meters and real−time pricing programs and a broad array of communication initiatives to increase customer awareness of approaches to manage their energy consumption. See Note 2 of the Combined Notes to Consolidated Financial Statements for further information regarding ComEd and PECO smart grid filings and stimulus grant awards. Finally, Exelon will offer more low−carbon electricity in the marketplace by increasing its investment in renewable power and adding capacity to existing nuclear plants through uprates.

Exelon has incorporated Exelon 2020 into its overall business plans and has an organized implementation effort underway. This implementation effort includes a periodic review and refinement of Exelon 2020 initiatives in light of changing market conditions. 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. As further legislation and regulation imposing requirements on emissions of air pollutants are promulgated, Exelon's emissions reduction efforts will position the company to benefit from the long−term positive impact of the requirements on capacity and energy prices while minimizing the impact of costs of compliance on Exelon's operations, cash flows or financial position.

The Exelon 2020 strategy is reviewed annually and updated to reflect changes in the market, regulations, technology and other factors that affect the merit of various GHG abatement options. In spite of the recent economic downturn, the decline in wholesale power prices and the uncertainty of Federal climate policy, Exelon 2020 strategy has been demonstrated to be a sustainable business strategy.

Renewable and Alternative Energy Portfolio Standards

Thirty−three states have adopted some form of RPS requirement. As previously described, Illinois and Pennsylvania 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.

Table of Contents

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, 2011, ComEd had purchased sufficient renewable energy resources or equivalents, such as RECs, to comply with the Illinois Settlement Legislation. See Note 2 and Note 18 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 2011, PECO was required to supply approximately 3.5% 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 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.

Similar to ComEd and PECO, Generation's retail electric business must source a portion of the electric load it serves in Illinois and Pennsylvania from renewable resources or approved equivalents such as RECs. While Generation is not directly affected by RPS or AEPS legislation from a compliance perspective, 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 Exelon Wind, Generation's hydroelectric and landfill gas generating stations and wind energy PPAs.

See Note 2 and Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

Executive Officers of the Registrants as of February 9, 2012

Name	Age	Position	Period
Rowe, John W.	66	Chairman, Chief Executive Officer and Director, Exelon	2000 − Present
		Chairman, Generation	2008 − Present
		Chairman, PECO	2007 − Present
		President, Exelon	2004 − 2008
		President, Generation	2007 − 2008
		Director, ComEd	2009 − Present
		Director, PECO	2005 − Present

Table of Contents

Name	Age	Position	Period
Crane, Christopher M.	53	President and Chief Operating Officer, Exelon; President, Generation	2008 − Present
		Chief Operating Officer, Generation	2007 − 2010
		Executive Vice President, Exelon	2007 − 2008
		President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon	2004 − 2007
Clark, Frank M.	66	Chairman and Chief Executive Officer, ComEd	2005 − Present
		Director, ComEd	2002 − Present
O'Brien, Denis P.	51	Chief Executive Officer, PECO; Executive Vice President, Exelon	2007 − Present
		President and Director, PECO	2003 − Present
Gillis, Ruth Ann M.	57	President, Exelon Business Services Company	2005 − Present
		Executive Vice President, Exelon	2008 − Present
		Chief Administrative and Diversity Officer, Exelon	2010 − Present
		Chief Diversity Officer, Exelon	2009 − 2010
		Senior Vice President, Exelon	2002 − 2008
Von Hoene Jr., William A.	58	Executive Vice President, Finance and Legal, Exelon	2009 − Present
		Executive Vice President and General Counsel, Exelon	2008 − 2009
		Senior Vice President, Exelon Business Services Company	2004 − 2009
		Senior Vice President, Exelon	2006 − 2008
Hilzinger, Matthew F.	48	Senior Vice President and Chief Financial Officer, Exelon; Chief Financial Officer, Generation	2008 − Present
		Treasurer, Exelon, Generation and Exelon Business Services Company; Assistant Treasurer, ComEd; Vice President, Exelon Business Services Company	2011 − Present
		Senior Vice President and Corporate Controller, Exelon	2005 − 2008
Cornew, Kenneth W.	46	Senior Vice President, Exelon; President, Power Team	2008 − Present
		Senior Vice President, Trading and Origination, Power Team	2007 − 2008
Dominguez, Joseph	48	Senior Vice President, Federal Regulatory Affairs & Public Policy, Exelon	2010 − Present
		Senior Vice President, State Governmental Affairs, Generation	2010 − Present
		Senior Vice President, State Regulatory Affairs and General Counsel, Generation	2010 − 2010
		Senior Vice President, Communications and Public Affairs, Exelon	2009 − 2010
		Senior Vice President, Exelon Business Services Company; Senior Vice President, Generation	2007 − 2010
		Vice President and Associate General Counsel, Exelon Business Services Company	2004 − 2007

Table of Contents

Name	Age	Position	Period
Pramaggiore, Anne R.	53	President and Chief Operating Officer, ComEd	2009 − Present
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 − 2009
		Senior Vice President, Regulatory and External Affairs, ComEd	2005 − 2007
Bradford, Darryl M.	56	Senior Vice President and General Counsel, Exelon	2010 − Present
		General Counsel, ComEd	2007 − 2010
		Senior Vice President, Regulatory and Energy Policy, ComEd	2009 − 2010
		Senior Vice President, ComEd	2007 − 2009
DesParte, Duane M.	48	Vice President and Corporate Controller, Exelon	2008 − Present
		Vice President, Finance, Exelon Business Services Company	2007 − 2008

Generation

Name	Age	Position	Period
Rowe, John W.	66	Chairman, Generation	2008 − Present
		Chairman, Chief Executive Officer and Director, Exelon	2000 − Present
		Chairman, PECO	2007 − Present
		President, Generation	2007 − 2008
		President, Exelon	2004 − 2008
		Director, ComEd	2009 − Present
		Director, PECO	2005 − Present
Crane, Christopher M.	53	President and Chief Operating Officer, Exelon; President, Generation	2008 − Present
		Chief Operating Officer, Generation	2007 − 2010
		Executive Vice President, Exelon	2007 − 2008
		President and Chief Nuclear Officer, Exelon Nuclear; Senior Vice President, Exelon	2004 − 2007
Pardee, Charles G.	52	Senior Vice President and Chief Operating Officer, Generation	2010 − Present
		President, Exelon Nuclear	2008 −2010
		Chief Nuclear Officer, Generation	2007 − 2010
		Senior Vice President, Generation	2007 − 2008
		Chief Operating Officer, Generation	2005 − 2007
Cornew, Kenneth W.	46	Senior Vice President, Exelon; President, Power Team	2008 − Present
		Senior Vice President, Trading and Origination, Power Team	2007 − 2008
Pacilio, Michael J.	51	President, Exelon Nuclear and Chief Nuclear Officer, Generation	2010 − Present
		Chief Operating Officer, Exelon Nuclear	2007 − 2010
		Senior Vice President, Mid−West PWR Operations, Exelon Nuclear	2005 − 2007

[Table of Contents](#)

Name	Age	Position	Period
Garg, Sunil	45	Senior Vice President, Generation; President, Exelon Power	2010 − Present
		Senior Vice President, Human Resources, Exelon; Senior Vice President, Exelon Business Services Company	2009 − 2010
		Vice President, Exelon Business Services Company	2007 − 2009
		Director of Integrated Business Services, Exelon Business Services Company	2004 − 2007
Dominguez, Joseph	48	Senior Vice President, State Governmental Affairs, Generation	2010 − Present
		Senior Vice President, Federal Regulatory Affairs & Public Policy, Exelon	2010 − Present
		Senior Vice President, State Regulatory Affairs and General Counsel, Generation	2010 − 2010
		Senior Vice President, Communications and Public Affairs, Exelon	2009 − 2010
		Senior Vice President, Exelon Business Services Company; Senior Vice President, Generation	2007 − 2010
		Vice President and Associate General Counsel, Exelon Business Services Company	2004 − 2007
Hilzinger, Matthew F.	48	Senior Vice President and Chief Financial Officer, Exelon; Chief Financial Officer, Generation	2008 − Present
		Treasurer, Exelon, Generation and Exelon Business Services Company; Assistant Treasurer, ComEd; Vice President, Exelon Business Services Company	2011 − Present
		Senior Vice President and Corporate Controller, Exelon	2005 − 2008
Galvanoni, Matthew R.	39	Chief Accounting Officer, Generation; Vice President, Assistant Corporate Controller, Exelon Business Services Company	2009 − Present
		Vice President, Comptroller, Accountant and Controller, ComEd; Vice President and Controller, PECO	2007 − 2009

[Table of Contents](#)

ComEd

Name	Age	Position	Period
Clark, Frank M.	66	Chairman and Chief Executive Officer, ComEd	2005 − Present
		Director, ComEd	2002 − Present
Pramaggiore, Anne R.	53	President and Chief Operating Officer, ComEd	2009 − Present
		Executive Vice President, Customer Operations, Regulatory and External Affairs, ComEd	2007 − 2009
		Senior Vice President, Regulatory and External Affairs, ComEd	2005 − 2007
Hooker, John T.	63	Executive Vice President, Legislative and External Affairs, ComEd	2009 − Present
		Senior Vice President, State Governmental Affairs and Real Estate and Facilities, ComEd	2008 − 2009
		Senior Vice President, State, Legislative and Governmental Affairs, ComEd	2005 − 2008
Donnelly, Terence R.	51	Executive Vice President, Operations, ComEd	2009 − Present
		Senior Vice President, Transmission and Distribution, ComEd	2007 − 2009
		Senior Vice President, Technical Services, PECO; Senior Vice President, Technical Services, ComEd	2007 − 2007
		Vice President, Transmission and Substations, Exelon Energy Delivery; Vice President, Transmission and Substations, ComEd	2004 − 2007
Trpik Jr., Joseph R.	42	Senior Vice President, Chief Financial Officer and Treasurer, ComEd	2009 − Present
		Vice President & Assistant Corporate Controller, Exelon Business Services Company	2007 − 2009
		Vice President and Assistant Corporate Controller, Exelon	2004 − 2009
Marquez Jr., Fidel	50	Senior Vice President, Customer Operations, ComEd	2009 − Present
		Vice President of External Affairs and Large Customer Services, ComEd	2007 − 2009
O'Neill, Thomas S.	49	Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd	2010 − Present
		Senior Vice President, Exelon	2009 − 2010
		Senior Vice President, New Business Development, Generation; Senior Vice President, New Business Development, Exelon	2009 − 2009
		Vice President, New Plant Development, Generation	2007 − 2009
		Vice President, Licensing and Regulatory, Exelon Nuclear	2005 − 2007

[Table of Contents](#)

Name	Age	Position	Period
Anthony, J. Tyler	47	Senior Vice President, Distribution Operations, ComEd	2010 − Present
		Vice President, Transmission and Substations, ComEd	2007 − 2010
		Vice President, Transmission and Substations, PECO	2007 − 2007
		Vice President, Outage Planning and Services, Generation	2006 − 2007
Waden, Kevin J.	40	Vice President, Comptroller, Accountant and Controller, ComEd	2009 − Present
		Director of Accounting Operations, ComEd	2007 − 2009
		Director of Financial Reporting and Accounting Research, Exelon Energy Delivery	2003 − 2007

PECO

Name	Age	Position	Period
Rowe, John W.	66	Chairman, Generation	2008 − Present
		Chairman, Chief Executive Officer and Director, Exelon	2000 − Present
		Chairman, PECO	2007 − Present
		President, Generation	2007 − 2008
		President, Exelon	2004 − 2008
		Director. CornEd	2009 − Present
		Director, PECO	2005 − Present
O'Brien, Denis P.	51	Executive Vice President, Exelon; Chief Executive Officer, PECO	2007 − Present
		President and Director, PECO	2003 − Present
Adams, Craig L.	59	Senior Vice President and Chief Operating Officer, PECO	2007 − Present
		Senior Vice President and Chief Supply Officer, Exelon Business Services Company	2004 − 2007
Barnett, Phillip S.	48	Senior Vice President and Chief Financial Officer, PECO	2007 − Present
		Senior Vice President, Corporate Financial Planning, Exelon	2005 − 2007
Bonney, Paul R.	53	Vice President, Regulatory Affairs and General Counsel, PECO	2009 − Present
		General Counsel, Vice President & Assistant Secretary, PECO	2007 − 2009
		Vice President & Deputy General Counsel, Regulatory, Exelon Business Services Company	2001 − 2007
Diaz Jr., Romulo L.	65	Vice President, Governmental and External Affairs, PECO	2009 − Present
		Associate General Counsel, Exelon	2008 − 2009
		City Solicitor, City of Philadelphia	2005 − 2008
Acevedo, Jorge A.	40	Vice President and Controller, PECO	2009 − Present
		Assistant Treasurer, PECO	2010 − Present
		Assistant Controller, Generation	2007 − 2009
		Director of Accounting, Power Team division of Generation	2003 − 2007

ITEM 1A. RISK FACTORS

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

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

- ***Market and Financial Risks.*** Exelon's and Generation's market and financial risks include the risk of price fluctuations in the wholesale power markets. Wholesale power prices are a function of supply and demand, which in turn are driven by factors such as the price of fuels, in particular the price of natural gas and coal, that drive the wholesale market prices that Generation's nuclear power plants receive, the rate of expansion of subsidized low carbon generation such as wind energy in the markets in which Generation's output is sold, and the impacts on energy demand of factors such as weather, economic conditions and implementation of energy efficiency and demand response programs.

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

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

- ***Risks Related to the Pending Merger with Constellation.*** As a result of the merger agreement announced with Constellation on April 28, 2011, Exelon is subject to additional risks.

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

Market and Financial Risks

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

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

The wholesale spot market price of electricity for each hour is generally determined by the marginal cost of supplying the next unit of electricity to the market during that hour. Many times, the next unit of electricity will be supplied from generating stations fueled by fossil fuels, and, therefore, the market price of power will reflect the market price of the marginal fuel. As such, changes in the market price of fossil fuels will cause comparable changes to the market price of power. For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing further downward pressure on natural gas prices and could reduce Generation's revenue, and, therefore, adversely affecting the its financial condition, results of operations and cash flows. In addition, further delay or elimination of EPA air quality regulations will tend to place downward pressure on market prices and could reduce Generation's revenue, and, therefore, adversely affect its financial condition, results of operations and cash flows. Further, in the event that alternative generation resources, such as wind and solar, are mandated through RPS or otherwise subsidized or encouraged through climate legislation or regulation and added to the supply, they could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region, including Generation, would sell their output, and could also result in an impairment of such plants.

The market price for electricity is also affected by changes in the demand for electricity. Worse than expected economic conditions, milder than normal weather, and the growth of energy efficiency and demand response programs can depress demand. The result is that higher−cost generating resources do not run as frequently, putting downward pressure on market prices for electricity. The continued sluggish economy in the United States has in fact led to a slow down in the growth of demand for electricity. If this continues, it could adversely affect the Registrants' ability to pay dividends or fund other discretionary uses of cash such as growth projects. A slow recovery could result in a prolonged depression of or further decline in commodity prices, which could also adversely affect Exelon's and Generation's results of operations, cash flows and financial position.

In addition to price fluctuations, Generation is exposed to other risks in the wholesale power market that are beyond its control and may negatively affect its results of operations. (Exelon and Generation)

Credit Risk. In the bilateral markets, Generation is exposed to the risk that counterparties that owe Generation money, or are obligated to purchase energy or fuel from Generation, will not perform their obligations for operational or financial reasons. In the event the counterparties to these arrangements fail to perform, Generation might be forced to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, to the extent of amounts, if any, already paid to the counterparties. In the spot markets, Generation is exposed to risk as a result of default sharing mechanisms that exist within certain markets, primarily RTO's and ISO's, the purpose of which is to spread such risk across all market participants. Generation is also a party to agreements with entities in the energy sector that have experienced rating downgrades or other financial difficulties.

In addition, Generation's retail sales subject it to credit risk through competitive electricity and natural gas supply activities to serve commercial and industrial companies. Retail credit risk results when customers default on their contractual obligations. This risk represents the loss that may be incurred due to the nonpayment of a customer's account balance, as well as the loss from the resale of energy previously committed to serve the customer.

Unstable Markets. The wholesale spot markets remain evolving markets that vary from region to region and are still developing practices and procedures. Problems in or the failure of any of these markets could adversely affect Generation's business. In addition, a significant decrease in market participation could affect market liquidity and have a detrimental effect on market stability.

Market performance and other factors may decrease the value of decommissioning trust funds and benefit plan assets and increase the related obligations, which then could require significant additional funding. (Exelon, Generation, ComEd and PECO)

Disruptions in the capital markets and their actual or perceived effects on particular businesses and the greater economy may adversely affect the value of the investments held within Generation's NDTs and Exelon's employee benefit plan trusts. The Registrants have significant obligations in these areas and Exelon and Generation hold substantial assets in these trusts to meet those obligations. The asset values are subject to market fluctuations and will yield uncertain returns, which may fall below the Registrants' projected return rates. A decline in the market value of the NDT fund investments may increase the funding requirements to decommission Generation's nuclear plants. A decline in the market value of the pension and other postretirement benefit plan assets will increase the funding requirements associated with Exelon's pension and other postretirement benefit plans. Additionally, Exelon's pension and other postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit costs and funding requirements. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions or changes to Social Security or Medicare eligibility requirements may also increase the costs and funding requirements of the obligations related to the pension and other postretirement benefit plans. If future increases in pension and other postretirement costs as a result of reduced plan assets or other factors are not recoverable from ComEd and PECO customers, the results of operations and financial positions of ComEd and PECO could be negatively affected. Ultimately, if the Registrants are unable to manage the decommissioning trust funds and benefit plan assets and obligations, their results of operations and financial positions could be negatively affected.

Unstable capital and credit markets and increased volatility in commodity markets may adversely affect the Registrants' businesses in several ways, including the availability and cost of short−term funds for liquidity requirements, the Registrants' ability to meet long−term commitments, Generation's ability to hedge effectively its generation portfolio, and the competitiveness and liquidity of energy markets; each could adversely affect the Registrants' financial condition, results of operations and cash flows. (Exelon, Generation, ComEd and PECO)

The Registrants rely on the capital markets, particularly for publicly offered debt, as well as the banking and commercial paper markets, to meet their financial commitments and short−term liquidity needs if internal funds are not available from the Registrants' respective operations. Disruptions in the capital and credit markets in the United States or abroad can adversely affect the Registrants' ability to access the capital markets or draw on their respective bank revolving credit facilities. The Registrants' access to funds under those credit facilities is dependent on the ability of the banks that are parties to the facilities to meet their funding commitments. Those banks may not be able to meet their funding commitments to the Registrants if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests from the Registrants and other borrowers within a short period of time. Longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in the deferral of discretionary capital expenditures, changes to Generation's hedging strategy to reduce collateral−posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

In addition, the Registrants have exposure to worldwide financial markets, including Europe. 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, 2011, approximately 35%, or $2.7 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $7.7 billion in aggregate total commitments of which $6.8 billion was available as of December 31, 2011. There were no borrowings under the Registrants' credit facilities as of December 31, 2011. See Note 10 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

The strength and depth of competition in competitive energy markets depend heavily on active participation by multiple trading parties, which could be adversely affected by disruptions in the capital and credit markets and legislative and regulatory initiatives that may affect participants in commodities transactions. Reduced capital and liquidity and failures of significant institutions that participate in the energy markets could diminish the liquidity and competitiveness of energy markets that are important to the respective businesses of the Registrants. Perceived weaknesses in the competitive strength of the energy markets could lead to pressures for greater regulation of those markets or attempts to replace market structures with other mechanisms for the sale of power, including the requirement of long−term contracts such as the financial swap contract between Generation and ComEd as described further in Note 2 of the Combined Notes to Consolidated Financial Statements, which could have a material adverse effect on Exelon's and Generation's results of operations and cash flows.

If any of the Registrants were to experience a downgrade in its credit ratings to below investment grade or otherwise fail to satisfy the credit standards of its trading counterparties, it would be required to provide significant amounts of collateral under its agreements with counterparties and could experience higher borrowing costs. (Exelon, Generation, ComEd and PECO)

Generation's business is subject to credit quality standards that may require market participants to post collateral for their obligations. If Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating) or otherwise fail to satisfy the credit standards of trading counterparties, it would be required under its hedging arrangements to provide collateral in the form of letters of credit or cash, which may have a material adverse effect upon its liquidity. The amount of collateral required to be provided by Generation at any point in time is dependent on a variety of factors, including (1) the notional amount of the applicable hedge, (2) the nature of counterparty and related agreements, and (3) changes in power or other commodity prices. In addition, if Generation were downgraded, it could experience higher borrowing costs as a result of the downgrade. Generation could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the power generation industry or Generation has deteriorated. Changes in ratings methodologies by the credit rating agencies could also have a negative impact on the ratings of Generation.

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

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

Either or both ComEd and PECO could experience a downgrade in its ratings if any of the credit rating agencies concludes that the level of business or financial risk and overall creditworthiness of the utility industry in general or ComEd or PECO in particular has deteriorated. ComEd or PECO could experience a downgrade if the current regulatory environments in Illinois and Pennsylvania become less predictable by materially lowering returns for utilities in the applicable state or adopting other measures to mitigate higher electricity prices. Additionally, the ratings for ComEd or PECO could be downgraded if its financial results are weakened from current levels due to weaker operating performance or due to a failure to properly manage its capital structure. In addition, changes in ratings methodologies by the agencies could also have a negative impact on the ratings of ComEd or PECO.

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

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

Generation's financial performance may be negatively affected by price volatility, availability and other risk factors associated with the procurement of nuclear and fossil fuel. (Exelon and Generation)

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

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

Generation's asset−based power position as well as its power marketing, fuel procurement and other commodity trading activities expose Generation to risks of commodity price movements. Generation attempts to manage this exposure through enforcement of established risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate all risks associated with these activities. Even when its policies and procedures are followed, and decisions are made based on projections and estimates of future performance, results of operations may be diminished if the judgments and assumptions underlying those decisions prove to be incorrect. Factors, such as future prices and demand for power and other energy−related commodities, become more difficult to predict and the calculations become less reliable the further into the future estimates are made. As a result, Generation cannot predict the impact that its commodity trading activities and risk management decisions may have on its business, operating results or financial position.

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

Generation may not be able to effectively respond to increased demand for energy. (Exelon and Generation)

Generation's financial growth may depend in part on its ability to respond to increased demand for energy. If demand for electricity rises in the future, it may be necessary for the market to increase capacity through the construction of new generating facilities. Development by Generation of new generating facilities would require the commitment of substantial capital resources, including access to the capital markets. The wholesale markets for electricity and certain states' statutes contemplate that future generation will be built in those markets at the risk of market participants. Thus, the ability of Generation to recover the costs of and to earn an adequate return on any future investment in generating facilities will be dependent on its ability to build, finance and efficiently operate facilities that are competitive in those markets. Additionally, construction of new generating facilities by Generation in markets in which it currently competes would be subject to market concentration tests administered by FERC. If Generation cannot pass the tests administered by FERC, Generation could be limited in how it responds to increased demand for energy.

Financial performance and load requirements may be adversely affected if Generation is unable to effectively manage its power portfolio. (Exelon and Generation)

A significant portion of Generation's power portfolio is used to provide power under procurement contracts with ComEd, PECO and other customers. To the extent portions of the power portfolio are not needed for that purpose, Generation's output is sold in the wholesale market. To the extent its power portfolio is not sufficient to meet the requirements of its customers under the related agreements, Generation must purchase power in the wholesale power markets. Generation's financial results may be negatively affected if it is unable to cost−effectively meet the load requirements of its customers, manage its power portfolio and effectively address the changes in the wholesale power markets.

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

1999 sale of fossil generating assets. The IRS has challenged Exelon's 1999 tax position on an involuntary conversion and like−kind exchange transaction. In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions and for the IRS to withdraw its assertion of a $110 million substantial understatement penalty related to the involuntary conversion position. However, Exelon and IRS Appeals failed to reach a settlement on the like−kind exchange position. Exelon expects to initiate litigation on this matter during 2012. If the IRS is successful in its challenge to the like−kind exchange position, it would accelerate future income tax payments and increase interest expense related to the deferred tax gain that would become currently payable. As of December 31, 2011, Exelon's potential cash outflow, including tax and interest, could be as much as $860 million, of which $550 million would be paid by ComEd and the remainder by Exelon. If the deferral were successfully challenged by the IRS, Exelon's results of operations could also be negatively impacted due to increased interest expense of up to $260 million, net of tax, of which $200 million would be recorded at ComEd and the remainder at Exelon. In addition to attempting to impose tax on the like−kind exchange position, the IRS has asserted penalties for a substantial understatement of tax, which could result in an after−tax charge of $86 million to Exelon's and ComEd's results of operations should the IRS prevail in asserting the penalties. The timing effects of the final resolution of the like−kind exchange matter are unknown. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information.

Tax reserves and the recoverability of deferred tax assets. The Registrants are required to make judgments in order to estimate their obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment−related taxes and ongoing appeals issues related to these tax matters. These judgments include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by the tax authorities. The Registrants also estimate their ability to utilize tax benefits, including those in the form of carryforwards and tax credits. See Notes 1 and 11 of the Combined Notes to Consolidated Financial Statements for additional information.

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

ComEd's and PECO's current procurement plans include purchasing power through contracted suppliers and in the spot market. ComEd's and PECO's costs of purchased power are charged to customers without a return or profit component. For PECO, purchased natural gas costs are charged to customers with no return or profit component. Purchased power and natural gas prices fluctuate based on their relevant supply and demand. Significantly higher rates related to purchased power and natural gas can result in declines in customer usage, lower electric transmission and distribution revenues and potentially additional uncollectible accounts expense for ComEd and PECO as well as lower gas distribution revenues for PECO. Also, ComEd's and PECO's cash flows can be affected by differences between the time period when electricity and natural gas are purchased and the ultimate recovery from customers.

In addition to increased purchased power charges for ComEd and PECO customers and purchased natural gas costs for PECO customers, the impact of economic downturns on ComEd and PECO's customers, such as unemployment for residential customers and less demand for products and services provided by commercial and industrial customers, and the related regulatory limitations on residential service terminations may result in an increase in the number of uncollectible customer balances, which would negatively impact ComEd's and PECO's results from operations and cash flows. See ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for further discussion of the Registrants' credit risk.

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

Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues. Extreme weather conditions or damage resulting from storms may stress ComEd's and PECO's transmission and distribution systems, resulting in increased maintenance and capital costs and limiting each company's ability to meet peak customer demand. These extreme conditions may have detrimental effects on ComEd's and PECO's results of operations and cash flows.

Generation's operations are also affected by weather, which affects demand for electricity as well as operating conditions. To the extent that weather is warmer in the summer or colder in the winter than assumed, Generation may require greater resources to meet its contractual commitments. Extreme weather conditions or storms may affect the availability of generation and its transmission, limiting Generation's ability to source or send power to where it is sold. In addition, drought−like conditions limiting water usage can impact Generation's ability to run certain generating assets at full capacity. These conditions, which cannot be accurately predicted, may have an adverse effect by causing Generation to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

Certain long−lived assets recorded on the Registrants' statements of financial position may become impaired, which would result in write−offs of the impaired amounts. (Exelon, Generation, ComEd and PECO)

Long−lived assets represent the single largest asset class on the Registrants' statement of financial position. Specifically, long−lived assets account for 59%, 49%, 58% and 64% of total assets for Exelon, Generation, ComEd and PECO, respectively, as of December 31, 2011. The Registrants evaluate for impairment the carrying value of long−lived assets to be held and used whenever indications of impairment exist. Factors such as the business climate, including current energy and market conditions, environmental regulation, and the condition of assets are considered when evaluating long−lived assets for impairment. An impairment would require the Registrants to reduce the long−lived asset through a non−cash charge to expense by the amount of the impairment, and such an impairment could have a material adverse impact on the Registrants' results of operations.

Exelon holds certain investments in coal−fired plants in Georgia and Texas subject to long−term leases extending through 2028−2032. On an annual basis, Exelon reviews the estimated residual values of these leased assets to determine whether any indications of impairment exist. In determining the estimate of residual value, the expectation of future market conditions, including commodity prices, is considered. An impairment would require Exelon to reduce the value of its investment in the plants through a non−cash charge to expense. Such an impairment could have a material adverse impact on Exelon's results of operations.

Exelon and ComEd had approximately $2.6 billion of goodwill recorded at December 31, 2011 in connection with the merger between PECO and Unicom Corporation, the former parent company of ComEd. Under GAAP, goodwill remains at its recorded amount unless it is determined to be impaired, which is generally based upon an annual analysis that compares the implied fair value of the goodwill to its carrying value. If an impairment occurs, the amount of the impaired goodwill will be written−off and expensed, reducing equity. The actual timing and amounts of any goodwill impairments will depend on many sensitive, interrelated and uncertain variables. A fully successful IRS challenge to Exelon's and ComEd's like−kind exchange income tax position or adverse regulatory actions such as early termination of EIMA in combination with changes in significant assumptions used in estimating ComEd's fair value (e.g., discount and growth rates, utility sector market performance and transactions, operating and capital expenditure requirements and the fair value of debt) could result in an impairment. Such an impairment would result in a non−cash charge to expense, which could have a material impact on Exelon's and ComEd's operating results.

See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Critical Accounting Policies and Estimates and Notes 5 and 7 of the Combined Notes to the Consolidated Financial Statements for additional discussion on long−lived asset and goodwill impairments.

The Registrants' businesses are capital intensive and the costs of capital projects may be significant. (Exelon, Generation, ComEd and PECO)

The Registrants' businesses are capital intensive and require significant investments by Generation in energy generation and by ComEd and PECO in transmission and distribution infrastructure projects. The Registrants' results of operations, financial condition, or cash flows could be adversely affected if they were unable to effectively manage their capital projects or raise the necessary capital. See ITEM 1. BUSINESS for further information regarding the Registrants' potential future capital expenditures.

Exelon and its subsidiaries have guaranteed the performance of third parties, which may result in substantial costs in the event of non−performance. (Exelon, Generation, ComEd and PECO)

The Registrants have issued certain guarantees of the performance of others, which obligate Exelon or its subsidiaries to perform in the event that the third parties do not perform. In the event of non−performance by the third parties, the Registrants could incur substantial cost to fulfill their obligations under these guarantees. Such performance guarantees could have a material impact on the operating results, financial condition, or cash flows of the Registrants. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

Due to its significant contractual agreements with ComEd, Generation will be negatively affected in the event of non−performance or change in the creditworthiness of ComEd. (Exelon and Generation)

Generation currently provides power under procurement contracts with ComEd for a significant portion of ComEd's electricity supply requirements. In addition, Generation entered into a financial swap contract with ComEd, effective August 2007, to hedge a portion of ComEd's electricity supply requirements through May 2013. Consequently, Generation is highly dependent on ComEd's continued payments under these contracts and would be adversely affected by negative events impacting these contracts, including the non−performance or a significant change in the creditworthiness of ComEd. A default by ComEd under these contracts would have an adverse effect on Generation's results of operations and financial position.

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

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

Regulatory and Legislative Risks

The Registrants' generation and energy delivery businesses are highly regulated and could be subject to adverse regulatory and legislative actions. Fundamental changes in regulation or legislation could disrupt the Registrants' business plans and adversely affect their operations and financial results. (Exelon, Generation, ComEd and PECO)

Substantially all aspects of the businesses of the Registrants are subject to comprehensive Federal or state regulation and legislation. Further, Exelon's and Generation's operating results and cash flows are heavily dependent upon the ability of Generation to sell power at market−based rates, as opposed to cost−based or other similarly regulated rates, and Exelon's, ComEd's and PECO's operating results and cash flows are heavily dependent on the ability of ComEd and PECO to recover their costs for the retail purchase and distribution of power to their customers. In the planning and management of operations, the Registrants must address the effects of regulation on their businesses and changes in the regulatory framework, including initiatives by Federal and state legislatures, RTOs, ratemaking agencies and taxing authorities. Fundamental changes in regulations or other adverse legislative actions affecting the Registrants' businesses would require changes in their business planning models and operations and could adversely affect their results of operations, cash flows and financial position.

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

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

Federal and state legislative and regulatory bodies are facing pressures to address consumer concerns that energy prices in wholesale markets are too high because the competitive model is not working, and, therefore, are facing calls for some form of re−regulation or some other means of reducing wholesale market prices. As the energy markets continue to mature, if the number of wholesale market power participants entering procurement proceedings shrinks, this could also influence how certain regulators and legislators view the effectiveness of these competitive markets.

The criticism of restructured electricity markets, which has escalated in recent years as retail rate freezes have expired, is expected to continue. Generation is dependent on robust and competitive wholesale energy markets to achieve its business objectives.

Approximately 75% of Generation's generating resources, which include directly owned assets and capacity obtained through long−term contracts, are located in the region encompassed by PJM. Generation's future results of operations will depend on 1) FERC's continued adherence to and support for policies that favor the preservation of competitive wholesale power markets, such as PJM's, and (2) the absence of material changes to market structures that would limit or otherwise negatively affect the competitiveness of the PJM market. Generation could also be adversely affected by state laws designed to reduce wholesale prices artificially below competitive levels, such as the New Jersey Capacity Legislation. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to the New Jersey Capacity Legislation.

In addition, FERC's application of its Order 697 and its subsequent revisions could pose a risk that Generation will have difficulty satisfying FERC's tests for market−based rates. Since Order 697 became final in June 2007, Generation has obtained orders affirming Generation's authority to sell at market−based rates and none denying that authority. Generation's most recent submission seeking reauthorization to sell at market−based rates was accepted by FERC on June 22, 2011 for the PJM region.

The Dodd−Frank Wall Street Reform and Consumer Protection Act (Dodd−Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis that unfolded during the Fall of 2008. Dodd−Frank ushers in a brand new regulatory regime applicable to the over−the−counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio. The significance of the effect on Generation will depend in part on whether it is determined to be a swap dealer or a qualifying end−user through a self−identification process, based on the meaning of those terms established in the final rules. If Generation is deemed a swap dealer, it will be required to register with the CFTC and execute most bilateral OTC derivative transactions through an exchange or central clearinghouse. This requirement could cause Generation to commit substantial additional capital to support the business and to cover increases in its collateral costs associated with margin requirements of the major exchanges such as the NYMEX. Generation would also face increased reporting and record−keeping requirements, would have to abide by CFTC−specified business conduct standards, and adhere to position limits in a potentially broad range of energy commodities.

Even if Generation is not deemed a swap dealer, it will still face additional regulatory obligations under Dodd−Frank, including some reporting requirements, clearing some additional transactions that it would otherwise enter into over−the−counter, and having to adhere to position limits. More fundamentally, however, the total burden that the rules could impose on all market participants could cause liquidity in the bilateral OTC swaps market to decreases substantially. As Generation's hedging program relies heavily on its ability to access the current bilateral OTC swaps market, the new rules could impede Generation's ability to meet its hedge targets in a cost−effective manner. Generation continues to monitor and participate in the rulemaking process. Generation cannot predict the ultimate outcome that Dodd−Frank will have on its results of operations, cash flows or financial position.

Generation's affiliation with ComEd and PECO, together with the presence of a substantial percentage of Generation's physical asset base within the ComEd and PECO service territories, could increase Generation's cost of doing business to the extent future complaints or challenges regarding ComEd and/or PECO retail rates result in settlements or legislative or regulatory requirements funded in part by Generation. (Exelon and Generation)

Generation has significant generating resources within the service areas of ComEd and PECO and makes significant sales to each of them. Those facts tend to cause Generation to be directly affected by developments in those markets. Government officials, legislators and advocacy groups are aware of Generation's affiliation with ComEd and PECO and its sales to each of them. In periods of rising utility rates, particularly when driven by increased costs of energy production and supply, those officials and advocacy groups may question or challenge costs incurred by ComEd or PECO, including transactions between Generation, on the one hand, and ComEd or PECO, on the other hand, regardless of any previous regulatory processes or approvals underlying those transactions. The prospect of such challenges may increase the time, complexity and cost of the associated regulatory proceedings, and the occurrence of such challenges may subject Generation to a level of scrutiny not faced by other unaffiliated competitors in those markets. In addition, government officials and legislators may seek ways to force Generation to contribute to efforts to mitigate potential or actual rate increases, through measures such as generation−based taxes and contributions to rate−relief packages.

The Registrants may incur substantial costs to fulfill their obligations related to environmental and other matters. (Exelon, Generation, ComEd and PECO)

The businesses which the Registrants operate are subject to extensive environmental regulation and legislation by local, state and Federal authorities. These laws and regulations affect the manner in which the Registrants conduct their operations and make capital expenditures. These regulations affect how the Registrants handle air and water emissions and solid waste disposal. Violations of these emission and disposal requirements can subject the Registrants to enforcement actions, capital expenditures to bring existing facilities into compliance, additional operating costs for remediation and clean−up costs, civil penalties and exposure to third parties' claims for alleged health or property damages or operating restrictions to achieve compliance. In addition, the Registrants are subject to liability under these laws for the remediation costs for environmental contamination of property now or formerly owned by the Registrants and of property contaminated by hazardous substances they generate. The Registrants have incurred and expect to incur significant costs related to environmental compliance, site remediation and clean−up. Remediation activities associated with MGP operations conducted by predecessor companies are one component of such costs. Also, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

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

Additionally, Generation is subject to exposure for asbestos−related personal injury liability alleged at certain current and formerly owned generation facilities. Future legislative action could require Generation to make a material contribution to a fund to settle lawsuits for alleged asbestos−related disease and exposure.

In some cases, a third party who has acquired assets from a Registrant has assumed the liability the Registrant may otherwise have for environmental matters related to the transferred property. If the transferee fails to discharge the assumed liability, a regulatory authority or injured person could attempt to hold the Registrant responsible, and the Registrant's remedies against the transferee may be limited by the financial resources of the transferee. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.

Changes in ComEd's and PECO's terms and conditions of service, including their respective rates, are subject to regulatory approval proceedings and/or negotiated settlements that are at times contentious, lengthy and subject to appeal, which lead to uncertainty as to the ultimate result and which may introduce time delays in effectuating rate changes. (Exelon, ComEd and PECO)

ComEd and PECO are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for ComEd or PECO to recover its costs by the time the rates become effective. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates can be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, MGP remediation, smart grid infrastructure, and energy efficiency and demand response programs.

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

ComEd and PECO cannot predict the ultimate outcomes of any settlements or the actions by Illinois, Pennsylvania or Federal regulators in establishing rates, including the extent, if any, to which certain costs such as significant capital projects will be recovered or what rates of return will be allowed. Nevertheless, the expectation is that ComEd and PECO will continue to be obligated to deliver electricity to customers in their respective service territories and will also retain significant POLR and default service obligations to provide electricity and natural gas to certain groups of customers in their respective service areas who do not choose an alternative supplier. The ultimate outcome and timing of regulatory rate proceedings have a significant effect on the ability of ComEd and PECO, as applicable, to recover their costs and could have a material adverse effect on ComEd's and PECO's results of operations, cash flows and financial position. See Note 2 of the Combined Notes to the Consolidated Financial Statements for information on the recently enacted EIMA and appeals in connection with ComEd's 2007 and 2010 Illinois electric distribution rate cases.

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

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

Table of Contents

Federal and state legislation mandating the implementation of energy conservation programs that require the implementation of new technologies, such as smart meters and smart grid, have increased capital expenditures and could significantly impact ComEd and PECO, if timely cost recovery is not allowed. Furthermore, regulated energy consumption reduction targets and declines in customer energy consumption resulting from the implementation of new energy conservation technologies could lead to a decline in the revenues of Exelon, ComEd and PECO. For additional information, see ITEM 1. BUSINESS “Environmental Regulation−Renewable and Alternative Energy Portfolio Standards.”

ComEd and PECO are likely to be subject to higher transmission operating costs and investments in the future as a result of PJM’s RTEP and NERC compliance requirements. (Exelon, ComEd and PECO)

Uncertainties exist as to the construction of new transmission facilities, their cost and how those costs will be allocated to transmission system participants and customers. In accordance with a FERC order and related settlement, PJM’s RTEP requires the costs of new transmission facilities to be allocated across the entire PJM footprint for new facilities greater than or equal to 500 kV, and requires costs of new facilities less than 500 kV to be allocated to the beneficiaries of the new facilities. On August 6, 2009, the U.S. Court of Appeals for the Seventh Circuit remanded to FERC its decision related to allocation of new facilities 500 kV and above for further proceedings.

ComEd and PECO as transmission owners are subject to NERC compliance requirements. NERC provides guidance to transmission owners regarding assessments of transmission lines. The results of these assessments may require ComEd and PECO to incur incremental capital or operating and maintenance expenditures to ensure their transmission lines meet NERC standards. See Notes 2 and 18 of the Combined Notes to Consolidated Financial Statements for additional information.

The impact of not meeting the criteria of the FASB guidance for accounting for the effects of certain types of regulation could be material to Exelon, ComEd and PECO. (Exelon, ComEd and PECO)

As of December 31, 2011, Exelon, ComEd and PECO have concluded that the operations of ComEd and PECO meet the criteria of the authoritative guidance for accounting for the effects of certain types of regulation. If it is concluded in a future period that a separable portion of their businesses no longer meets the criteria, Exelon, ComEd and PECO are required to eliminate the financial statement effects of regulation for that part of their business. That action would include the elimination of any or all regulatory assets and liabilities that had been recorded in their Consolidated Balance Sheets and the recognition of a one−time extraordinary item in their Consolidated Statements of Operations. The impact of not meeting the criteria of the authoritative guidance could be material to the financial statements of Exelon, ComEd and PECO. At December 31, 2011, the extraordinary gain could have been as much as $1.8 billion (before taxes) as a result of the elimination of ComEd’s regulatory assets and liabilities. At December 31, 2011, the extraordinary charge could have been as much as $ 610 million (before taxes) as a result of the elimination of PECO’s regulatory assets and liabilities. Exelon would record the same amount of extraordinary gain and charge related to ComEd’s and PECO’s regulatory assets and liabilities, respectively. Further, Exelon would record a charge against OCI (before taxes) of up to $3.0 billion and $32 million for ComEd and PECO, respectively, related to Exelon’s regulatory assets associated with its defined benefit postretirement plans. The impacts and resolution of the above items could lead to an additional impairment of ComEd’s goodwill, which could be significant and at least partially offset the extraordinary gain discussed above. A significant decrease in equity as a result of any changes could limit the ability of ComEd and PECO to pay dividends under Federal and state law and cause significant volatility in future results of operations. See Notes 1, 2 and 7 of the Combined Notes to Consolidated Financial Statements for additional information regarding accounting for the effects of regulation, regulatory matters and ComEd’s goodwill, respectively.

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

Various stakeholders, including legislators and regulators, shareholders and non−governmental organizations, as well as other companies in many business sectors, including utilities, are considering ways to address the effect of GHG emissions on climate change. In 2009, select Northeast and Mid−Atlantic states implemented a model rule, developed via the RGGI, to regulate CO_2 emissions from fossil−fired generation. If carbon reduction regulation or legislation becomes effective, Exelon and Generation may incur costs either to limit further the GHG emissions from their operations or to procure emission allowance credits. The nature and extent of environmental regulation may also impact the ability of Exelon and its subsidiaries to meet the GHG emission reduction targets of Exelon 2020. For example, more stringent permitting requirements may preclude the construction of lower−carbon nuclear and gas−fired power plants. Similarly, a Federal RPS could increase the cost of compliance by mandating the purchase or construction of more expensive supply alternatives. For more information regarding climate change, see ITEM 1. BUSINESS “Global Climate Change” and Note 18 of the Combined Notes to Consolidated Financial Statements.

The Registrants could be subject to higher costs and/or penalties related to mandatory reliability standards. (Exelon, Generation, ComEd and PECO)

As a result of the Energy Policy Act of 2005, users, owners and operators of the bulk power transmission system, including Generation, ComEd and PECO, are subject to mandatory reliability standards promulgated by NERC and enforced by FERC. PECO as operator of a natural gas distribution system is also subject to mandatory reliability standards of the U.S. Department of Transportation. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with or changes in the reliability standards may subject the Registrants to higher operating costs and/or increased capital expenditures. In addition, the ICC and PAPUC impose certain distribution reliability standards on ComEd and PECO, respectively. If the Registrants were found not to be in compliance with the mandatory reliability standards, they could be subject to remediation costs as well as sanctions, which could include substantial monetary penalties.

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

The Registrants are involved in legal proceedings, claims and litigation arising out of their business operations, the most significant of which are summarized in Note 18 of the Combined Notes to Consolidated Financial Statements. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on the Registrants’ results of operations.

Operational Risks

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

Employees and contractors throughout the organization work in, and customers and the general public may be exposed to, potentially dangerous environments near operations. As a result, employees, contractors, customers and the general public are at risk for serious injury, including loss of life. Significant risks include nuclear accidents, dam failure, gas explosions, pole strikes and electric contact cases.

Natural disasters, war, acts and threats of terrorism, pandemic and other significant events may adversely affect Exelon's results of operations, its ability to raise capital and its future growth. (Exelon, Generation, ComEd and PECO)

Generation's fleet of nuclear power plants and ComEd's and PECO's distribution and transmission infrastructures could be impacted by natural disasters, such as seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive, which could result in increased costs, including supply chain costs. An extreme weather event within the Registrants' service areas can also directly affect their capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. An example of such an event was the 9.0 magnitude earthquake and ensuing tsunami experienced by Japan on March 11, 2011, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, which are operated by Tokyo Electric Power Co. Also, in 2011, the Mid−Atlantic region of the United States experienced a 5.8 magnitude earthquake and flooding associated with hurricane Irene and tropical storm Lee. These events increase the risk to Generation that the NRC or other regulatory or legislative bodies may change the laws or regulations governing, among other things, operations, maintenance, licensed lives, decommissioning, SNF storage, insurance, emergency planning, security and environmental and radiological aspects. In addition, natural disasters could affect the availability of a secure and economical supply of water in some locations, which is essential for Generation's continued operation, particularly the cooling of generating units. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect the Registrants' operations and their ability to raise capital.

Exelon does not know the impact that potential terrorist attacks could have on the industry in general and on Exelon in particular. As owner−operators of infrastructure facilities, such as nuclear, fossil and hydroelectric generation facilities and electric and gas transmission and distribution facilities, the Registrants face a risk that their operations would be direct targets of, or indirect casualties of, an act of terror. Any retaliatory military strikes or sustained military campaign may affect their operations in unpredictable ways, such as changes in insurance markets and disruptions of fuel supplies and markets, particularly oil. Instability in the financial markets as a result of terrorism, war, natural disasters, pandemic, credit crises, recession or other factors also may affect the Registrants' results of operations and its ability to raise capital. In addition, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased costs.

The Registrants would be significantly affected by the outbreak of a pandemic. Exelon has plans in place to respond to a pandemic. However, depending on the severity of a pandemic and the resulting impacts to workforce and other resource availability, the ability to operate its generating and transmission and distribution assets could be affected, resulting in decreased service levels and increased costs.

Generation's financial performance may be negatively affected by matters arising from its ownership and operation of nuclear facilities. (Exelon and Generation)

Nuclear capacity factors. Capacity factors, particularly nuclear capacity factors, significantly affect Generation's results of operations. Nuclear plant operations involve substantial fixed operating costs but produce electricity at low variable costs due to nuclear fuel costs typically being lower than fossil fuel costs. Consequently, to be successful, Generation must consistently operate its nuclear facilities at high capacity factors. Lower capacity factors increase Generation's operating costs by requiring Generation to produce additional energy from primarily its fossil facilities or purchase additional energy in the spot or forward markets in order to satisfy Generation's obligations to committed third−party sales, including ComEd and PECO. These sources generally have higher costs than Generation incurs to produce energy from its nuclear stations.

Nuclear refueling outages. Refueling outages are planned to occur once every 18 to 24 months and are currently planned to average approximately 26 days in duration for the nuclear plants operated by Generation. The total number of refueling outages, along with their duration, can have a significant impact on Generation's results of operations. When refueling outages at wholly and co−owned plants last longer than anticipated or Generation experiences unplanned outages, capacity factors decrease and Generation faces lower margins due to higher energy replacement costs and/or lower energy sales. Each 26−day outage, depending on the capacity of the station, will decrease the total nuclear annual capacity factor between 0.3% and 0.5%.

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

Spent nuclear fuel storage. The approval of a national repository for the storage of SNF, such as the one proposed for Yucca Mountain, Nevada, and the timing of such facility opening, will significantly affect the costs associated with storage of SNF, and the ultimate amounts received from the DOE to reimburse Generation for these costs. Through the NRC's "waste confidence" rule, the NRC has determined that, if necessary, spent fuel generated in any reactor can be stored safely and without significant environmental impacts for at least 60 years beyond the licensed life for operation, which may include the term of a revised or renewed license of that reactor, at its spent fuel storage basin or at either onsite or offsite independent spent fuel storage installations. Any regulatory action relating to the timing and availability of a repository for SNF may adversely affect Generation's ability to decommission fully its nuclear units. Furthermore, under its contract with the DOE, Generation would be required to pay the DOE a one−time SNF storage fee including interest of approximately $1 billion as of December 31, 2011, prior to the first delivery of SNF. Generation currently estimates 2020 to be the earliest date when the DOE will begin accepting SNF, which could be delayed by further regulatory action. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information on the spent nuclear fuel obligation.

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

Should a national policy for the disposal of SNF not be developed, the unavailability of a repository for SNF could become a consideration by the NRC during future nuclear license renewal proceedings, including applications for new licenses.

***Regulatory risk*.** The NRC may modify, suspend or revoke licenses, shut down a nuclear facility and impose civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms of the licenses for nuclear facilities. A change in the Atomic Energy Act or the applicable regulations or licenses may require a substantial increase in capital expenditures or may result in increased operating or decommissioning costs and significantly affect Generation's results of operations or financial position. Events at nuclear plants owned by others, as well as those owned by Generation, may cause the NRC to initiate such actions.

As an example, prior to the Fukushima Daiichi accident on March 11, 2011, the NRC had been evaluating seismic risk. After the Fukushima Daiichi accident, the NRC's focus on seismic risk intensified. As part of the NRC Near−Term Task Force (Task Force) review and evaluation of the Fukushima Daiichi accident, the Task Force recommended that plant operators conduct seismic reevaluations. In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force. These reevaluations could result in the required implementation of additional mitigation strategies or modifications. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon Corporation, Executive Overview for a more detailed discussion of the Task Force Recommendations.

***Operational risk*.** Operations at any of Generation's nuclear generation plants could degrade to the point where Generation has to shut down the plant or operate at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Generation may choose to close a plant rather than incur the expense of restarting it or returning the plant to full capacity. In either event, Generation may lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, Generation may not achieve the anticipated results under its series of planned power uprates across its nuclear fleet. For plants operated but not wholly owned by Generation, Generation may also incur liability to the co−owners. For the plant not wholly owned by Generation and operated by PSEG, Salem Units 1 and 2, from which Generation receives its share of the plant's output, Generation's results of operations are dependent on the operational performance of the co−owner operator and could be adversely affected by a significant event at those plants. Additionally, poor operating performance at nuclear plants not owned by Generation could result in increased regulation and reduced public support for nuclear−fueled energy, which could significantly affect Generation's results of operations or financial position. In addition, closure of generating plants owned by others, or extended interruptions of generating plants or failure of transmission lines, could effect transmission systems that could adversely affect the sale and delivery of electricity in markets served by Generation.

Nuclear major incident risk. Although the safety record of nuclear reactors generally has been very good, accidents and other unforeseen problems have occurred both in the United States and abroad. The consequences of a major incident can be severe and include loss of life and property damage. Any resulting liability from a nuclear plant major incident within the United States, owned by Generation or owned by others, may exceed Generation's resources, including insurance coverage. Uninsured losses and other expenses, to the extent not recovered from insurers or the nuclear industry, could be borne by Generation and could have a material adverse effect on Generation's results of operations or financial position. Additionally, an accident or other significant event at a nuclear plant within the United States or abroad, owned by others or Generation, may result in increased regulation and reduced public support for nuclear−fueled energy and significantly affect Generation's results of operations or financial position.

Nuclear insurance. As required by the Price−Anderson Act, Generation carries the maximum available amount of nuclear liability insurance. The required amount of nuclear liability insurance is $375 million for each operating site. Claims exceeding that amount are covered through mandatory participation in a financial protection pool. In addition, the U.S. Congress could impose revenue−raising measures on the nuclear industry to pay claims exceeding the $12.6 billion limit for a single incident.

Generation is a member of an industry mutual insurance company, NEIL, which provides property and business interruption insurance for Generation's nuclear operations. In 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. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional discussion of nuclear insurance.

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

Forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results may differ significantly from current estimates. The performance of capital markets also can significantly affect the value of the trust funds. Currently, Generation is making contributions to the trust funds of the former PECO units based on amounts being collected by PECO from its customers and remitted to Generation. While Generation has recourse to collect additional amounts from PECO customers (subject to certain limitations and thresholds), it has no recourse to collect additional amounts from ComEd customers or from the previous owners of Clinton, TMI Unit No. 1 and Oyster Creek generating stations, if there is a shortfall of funds necessary for decommissioning. If circumstances changed such that Generation would be unable to continue to make contributions to the trust funds of the former PECO units based on amounts collected from PECO customers, or if Generation no longer had recourse to collect additional amounts from PECO customers if there was a shortfall of funds for decommissioning, the adequacy of the trust funds related to the former PECO units may be negatively affected. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Ultimately, if the investments held by Generation's NDTs are not sufficient to fund the decommissioning of Generation's nuclear plants, Generation may be required to take steps, such as providing financial guarantees through letters of credit or parent company guarantees or making additional contributions to the trusts, which could be significant, to ensure that the trusts are adequately funded and that NRC minimum funding requirements are met. As a result, Generation's cash flows and financial position may be significantly adversely affected. See Note 12 of the Combined Notes to Consolidated Financial Statements for additional information.

Generation's financial performance may be negatively affected by risks arising from its ownership and operation of hydroelectric facilities. (Exelon and Generation)

FERC has the exclusive authority to license most non−Federal hydropower projects located on navigable waterways, Federal lands or connected to the interstate electric grid. The license for the Conowingo Hydroelectric Project expires August 31, 2014, and the license for the Muddy Run Pumped Storage Project expires on September 1, 2014. Generation cannot predict whether it will receive all the regulatory approvals for the renewed licenses of its hydroelectric facilities. If FERC does not renew the operating licenses for Generation's hydroelectric facilities or a station cannot be operated through the end of its operating license, Generation's results of operations could be adversely affected by increased depreciation rates and accelerated future decommissioning costs, since depreciation rates and decommissioning cost estimates currently include assumptions that license renewal will be received. Generation may also lose revenue and incur increased fuel and purchased power expense to meet supply commitments. In addition, conditions may be imposed as part of the license renewal process that may adversely affect operations, may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation's results of operations or financial position. Similar effects may result from a change in the Federal Power Act or the applicable regulations due to events at hydroelectric facilities owned by others, as well as those owned by Generation.

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

Failures of the equipment or facilities, including information systems, used in ComEd's and PECO's delivery systems can interrupt the electric transmission and electric and natural gas delivery, which could negatively impact related revenues, and increase maintenance and capital expenditures. Equipment or facilities failures can be due to a number of factors, including weather or information systems failure. Specifically, if the implementation of advanced metering infrastructure, smart grid or other technologies in ComEd or PECO's service territory fail to perform as intended or are not successfully integrated with billing and other information systems, ComEd and PECO's financial condition, results of operations, and cash flows could be adversely affected.

The aforementioned failures or those of other utilities, including prolonged or repeated failures, can affect customer satisfaction and the level of regulatory oversight and ComEd's and PECO's maintenance and capital expenditures. Regulated utilities, which are required to provide service to all customers within their service territory, have generally been afforded liability protections against claims by customers relating to failure of service. Under Illinois law, however, ComEd can be required to pay damages to its customers in some circumstances involving extended outages affecting large numbers of its customers, and those damages could be material to ComEd's results of operations and cash flows.

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

Demand for electricity within ComEd's and PECO's service areas could stress available transmission capacity requiring alternative routing or curtailment of electricity usage with consequent effects on operating costs, revenues and results of operations. Also, insufficient availability of electric supply to meet customer demand could jeopardize ComEd and PECO's ability to comply with reliability standards and strain customer and regulatory agency relationships. As with all utilities, potential concerns over transmission capacity or generation facility retirements could result in PJM or FERC requiring ComEd and PECO to upgrade or expand their respective transmission systems through additional capital expenditures.

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

Certain events, such as an employee strike, loss of contract resources due to a major event, and an aging workforce without appropriate replacements, may lead to operating challenges and increased costs for the Registrants. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. The Registrants are particularly affected due to the specialized knowledge required of the technical and support employees for their generation, transmission and distribution operations. If the Registrants are unable to successfully attract and retain an appropriately qualified workforce, their results of operations could be negatively affected.

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

The Registrants face information security risks as the owner−operators of generation, transmission and distribution facilities. A security breach of the Registrants' information systems could impact the operation of the generation fleet and/or reliability of the transmission and distribution system or subject them to financial harm associated with theft or inappropriate release of certain types of information. ComEd and PECO's deployment of smart meters throughout their service territories may increase the risk of damage from an intentional disruption of the system by third parties. The Registrants cannot accurately assess the probability that a security breach may occur, despite the measures taken by the Registrants to prevent such a breach, and are unable to quantify the potential impact of such an event. In addition, new or updated security regulations would require changes in current measures taken by the Registrants and could adversely affect their results of operations, cash flows and financial position.

The Registrants may make acquisitions that do not achieve the intended financial results. (Exelon, Generation, ComEd and PECO)

The Registrants may make investments and pursue mergers and acquisitions intended to fit their strategic objectives and improve their financial performance. It is possible that FERC, state public utility commissions or others may impose certain other restrictions on such transactions. Achieving the anticipated benefits of an investment is subject to a number of uncertainties, and failure to achieve the anticipated benefits could result in increased costs, decreases in the amount of expected revenues generated by the combined company and diversion of management's time and energy and could have an adverse effect on the combined company's business, financial condition, operating results and prospects.

Risks Related to the Pending Merger with Constellation

Because the market price of shares of Exelon common stock will fluctuate and the exchange ratio will not be adjusted to reflect such fluctuations, the merger consideration at the date of the closing may vary significantly from the date the merger agreement was executed.

Upon completion of the merger, each outstanding share of Constellation common stock will be converted into the right to receive 0.930 of a share of Exelon common stock. The number of shares of Exelon common stock to be issued pursuant to the merger agreement for each share of Constellation common stock will not change to reflect changes in the market price of Exelon or Constellation common stock. The market price of Exelon common stock at the time of completion of the merger may vary significantly from the market prices of Exelon common stock on the date the merger agreement was executed.

In addition, Exelon might not complete the merger until a significant period of time has passed after the respective special shareholder meetings to approve the merger occurred. Because Exelon will not adjust the exchange ratio to reflect any changes in the market value of Exelon common stock or Constellation common stock, the market value of the Exelon common stock issued in connection with the merger and the Constellation common stock surrendered in connection with the merger may be higher or lower than the values of those shares on earlier dates. Stock price changes may result from market assessment of the likelihood that the merger will be completed, changes in the business, operations or prospects of Exelon or Constellation prior to or following the merger, litigation or regulatory considerations, general business, market, industry or economic conditions and other factors both within and beyond the control of Exelon and Constellation. Neither Exelon nor Constellation is permitted to terminate the merger agreement solely because of changes in the market price of either company's common stock.

The combined company's assets, liabilities or results of operations could be adversely affected by unknown or unexpected events, conditions or actions that occur prior to the closing of the merger.

The Constellation assets, liabilities, business, financial condition, cash flows, operating results and prospects to be acquired or assumed by Exelon by reason of the merger could be adversely affected before or after the merger closing as a result of previously unknown events or conditions occurring or existing before the merger closing. Adverse changes in Constellation's business or operations could occur or arise as a result of actions by Constellation, legal or regulatory developments including the emergence or unfavorable resolution of pre−acquisition loss contingencies, deteriorating general business, market, industry or economic conditions, and other factors both within and beyond the control of Constellation. A significant decline in the value of Constellation assets to be acquired by Exelon or a significant increase in Constellation liabilities to be assumed by Exelon could adversely affect the combined company's future business, financial condition, cash flows, operating results and prospects.

The merger agreement contains provisions that limit each of Exelon's and Constellation's ability to pursue alternatives to the merger, which could discourage a potential acquirer of either Constellation or Exelon from making an alternative transaction proposal and, in certain circumstances, could require Exelon or Constellation to pay to the other a significant termination fee.

Under the merger agreement, Exelon and Constellation are restricted, subject to limited exceptions, from entering into alternative transactions in lieu of the merger. In general, unless and until the merger agreement is terminated, both Exelon and Constellation are restricted from, among other things, soliciting, initiating, knowingly encouraging or facilitating a competing acquisition proposal from any person. Each of the Exelon board of directors and the Constellation board of directors is limited in its ability to change its recommendation with respect to the merger−related proposals. Exelon or Constellation may terminate the merger agreement and enter into an agreement with respect to a superior proposal only if specified conditions have been satisfied, including compliance with the non−solicitation provisions of the merger agreement. These provisions could discourage a third party that may have an interest in acquiring all or a significant part of Exelon or Constellation from considering or proposing such an acquisition, even if such third party were prepared to pay consideration with a higher per share cash or market value than the consideration proposed to be received or realized in the merger, or might result in a potential competing acquirer proposing to pay a lower price than it would otherwise have proposed to pay because of the added expense of the termination fee that may become payable in certain circumstances. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation and a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon.

Exelon and Constellation will be subject to various uncertainties and contractual restrictions while the merger is pending that may cause disruption and could adversely affect their financial results.

Uncertainty about the effect of the merger on employees, suppliers and customers may have an adverse effect on Exelon and/or Constellation. These uncertainties may impair Exelon's and/or Constellation's ability to attract, retain and motivate key personnel until the merger is completed and for a period of time thereafter, as employees and prospective employees may experience uncertainty about their future roles with the combined company, and could cause customers, suppliers and others who deal with Exelon or Constellation to seek to change existing business relationships with Exelon or Constellation. The pursuit of the merger and the preparation for the integration may also place a burden on management and internal resources. Any significant diversion of management attention away from ongoing business concerns and any difficulties encountered in the transition and integration process could affect Exelon's and/or Constellation's financial results.

In addition, the merger agreement restricts each of Exelon and Constellation, without the other's consent, from making certain acquisitions and taking other specified actions while the merger is pending. These restrictions may prevent Exelon and/or Constellation from pursuing otherwise attractive business opportunities and making other changes to their respective businesses prior to completion of the merger or termination of the merger agreement.

If completed, the merger may not achieve its anticipated results, and Exelon and Constellation may be unable to integrate their operations in the manner expected.

Exelon and Constellation entered into the merger agreement with the expectation that the merger will result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of Exelon and Constellation can be integrated in an efficient, effective and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees, the disruption of each company's ongoing businesses, processes and systems or inconsistencies in standards, controls, procedures, practices, policies and compensation arrangements, any of which could adversely affect the combined company's ability to achieve the anticipated benefits of the merger as and when expected. The companies may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve these anticipated benefits could result in increased costs or decreases in the amount of expected revenues and could adversely affect the combined company's future business, financial condition, operating results and prospects.

The merger may not be accretive to earnings and may cause dilution to Exelon's earnings per share, which may negatively affect the market price of Exelon's common stock.

Exelon currently anticipates that the merger will be accretive to earnings per share in 2013, which is expected to be the first full year following completion of the merger. This expectation is based on preliminary estimates that are subject to change. Exelon also could encounter additional transaction and integration−related costs, may fail to realize all of the benefits anticipated in the merger or be subject to other factors that affect preliminary estimates. Any of these factors could cause a decrease in Exelon's adjusted earnings per share or decrease or delay the expected accretive effect of the merger and contribute to a decrease in the price of Exelon's common stock.

Exelon may record goodwill that could become impaired and adversely affect its operating results.

Accounting standards in the United States require that one party to the merger be identified as the acquirer. In accordance with these standards, the merger will be accounted for as an acquisition of Constellation common stock by Exelon and will follow the acquisition method of accounting for business combinations. The assets and liabilities of Constellation will be consolidated with those of Exelon. The excess of the purchase price over the fair values of Constellation's assets and liabilities, if any, will be recorded as goodwill.

The amount of goodwill, which could be material, will be allocated to the appropriate reporting units of the combined company. Exelon is required to assess goodwill for impairment at least annually by comparing the fair value of reporting units to the carrying value of those reporting units. To the extent the carrying value of any of those reporting units is greater than the fair value, a second step comparing the implied fair value of goodwill to the carrying amount would be required to determine if the goodwill is impaired. Such a potential impairment could result in a material charge that would have a material impact on Exelon's future operating results and consolidated balance sheet.

Pending litigation against Exelon and Constellation could result in an injunction preventing the completion of the merger or a judgment resulting in the payment of damages in the event the merger is completed and may adversely affect the combined company's business, financial condition or results of operations and cash flows following the merger.

Twelve purported class action lawsuits were filed against Constellation, each member of Constellation's board of directors, Exelon and Bolt Acquisition Corporation, a Maryland corporation and a wholly owned subsidiary of Exelon, in connection with the merger. Among other things, the lawsuits sought injunctive relief that would have prevented completion of the merger in accordance with the terms of the merger agreement. The parties to the litigation have reached a settlement that remains subject to court approval. If the settlement is not approved by the court, these lawsuits could prevent or delay completion of the merger and result in substantial costs to Exelon and Constellation, including any costs associated with the indemnification of directors and officers. Plaintiffs may file additional lawsuits against Exelon, Constellation and/or the directors and officers of either company in connection with the merger. The defense or settlement of any lawsuit or claim that remains unresolved at the time the merger is completed may adversely affect the combined company's business, financial condition, results of operations and cash flows.

The merger is subject to the receipt of consent or approval from governmental entities that could delay the completion of the merger or impose conditions that could have a material adverse effect on the combined company or that could cause abandonment of the merger.

Completion of the merger is conditioned upon the receipt of consents, orders, approvals or clearances, to the extent required, from the FERC, the NRC, the FCC, and the public utility commissions or similar entities in certain states in which the companies operate, including the Maryland Public Service Commission. The merger is also subject to review by the DOJ Antitrust Division, under the HSR Act, and the expiration or earlier termination of the waiting period (and any extension of the waiting period) applicable to the merger is a condition to closing the merger. As of February 9, 2012, the merger remains subject to the approval of the NRC, FERC and the Maryland Public Service Commission, which may impose conditions for approval beyond those already proposed by Exelon and Constellation. The shareholders of Exelon and Constellation approved the proposals required to complete the merger at the special meetings of the shareholders before any or all of the required regulatory approvals have been obtained and before all conditions to such approvals, if any, are known.

As a result, Exelon and Constellation may subsequently agree to conditions without seeking further shareholder approval, even if such conditions could have an adverse effect on Exelon, Constellation or the combined company.

Exelon and Constellation cannot provide assurance that all required regulatory consents or approvals will be obtained or that these consents or approvals will not contain terms, conditions or restrictions that would be detrimental to the combined company after the completion of the merger. The merger agreement generally permits each party to terminate the merger agreement if the final terms of any of the required regulatory consents or approvals require (1) any action that involves divesting, holding separate or otherwise transferring control over any nuclear or hydroelectric or pumped−storage generation assets of the parties or any of their respective subsidiaries or affiliates; or (2) any action (including any action that involves divesting, holding separate or otherwise transferring control over base−load capacity), without including those actions proposed by the parties' mutually agreed−upon analysis of mitigation to address the increased market concentration resulting from the merger and the concessions announced by the parties in the press release announcing the merger agreement, which would, individually or in the aggregate, reasonably be expected to have a material adverse effect on either party. Any substantial delay in obtaining satisfactory approvals, receipt of proceeds from required divestitures in an amount substantially lower than anticipated or the imposition of any terms or conditions in connection with such approvals could cause a material reduction in the expected benefits of the merger. If any such delays or conditions are serious enough, the parties may decide to abandon the merger.

Exelon cannot assure that it will be able to continue paying dividends at the current rate.

Exelon currently expects to pay dividends in an amount consistent with the dividend policy of Exelon in effect prior to the completion of the merger. However, there is no assurance that Exelon shareholders will receive the same dividends following the merger for reasons that may include any of the following factors:

- Exelon may not have enough cash to pay such dividends due to changes in Exelon's cash requirements, capital spending plans, financing agreements, cash flow or financial position;
- decisions on whether, when and in which amounts to make any future distributions will remain at all times entirely at the discretion of the Exelon board of directors, which reserves the right to change Exelon's dividend practices at any time and for any reason;
- the amount of dividends that Exelon may distribute to its shareholders is subject to restrictions under Pennsylvania law; and
- Exelon may not receive dividend payments from its subsidiaries in the same level that it has historically. The ability of Exelon's subsidiaries to make dividend payments to it is subject to factors similar to those listed above.

Exelon's shareholders have no contractual or other legal right to dividends that have not been declared.

If completed, the merger may adversely affect the combined company's ability to attract and retain key employees.

Current and prospective Exelon and Constellation employees may experience uncertainty about their future roles at the combined company following the completion of the merger. In addition, current and prospective Exelon and Constellation employees may determine that they do not desire to work for the combined company for a variety of possible reasons. These factors may adversely affect the combined company's ability to attract and retain key management and other personnel.

Failure to complete the merger could negatively affect the share prices and the future businesses and financial results of Exelon and Constellation.

Completion of the merger is not assured and is subject to risks, including the risks that approval of the transaction by governmental agencies will not be obtained or that certain other closing conditions will not be satisfied. If the merger is not completed, the ongoing businesses of Exelon or Constellation may be adversely affected and Exelon and Constellation will be subject to several risks, including:

- having to pay certain significant costs relating to the merger without receiving the benefits of the merger, including, in certain circumstances, a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation and a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon;
- Exelon and Constellation will have been subject to certain restrictions on the conduct of their businesses, which may have prevented them from making certain acquisitions or dispositions or pursuing certain business opportunities while the merger is pending; and

- the share price of Exelon or Constellation may decline to the extent that the current market prices reflect an assumption by the market that the merger will be completed.

Exelon and Constellation may incur unexpected transaction fees and merger−related costs in connection with the merger.

Exelon and Constellation expect to incur a number of non−recurring expenses, totalling approximately $150 million, associated with completing the merger, as well as expenses related to combining the operations of the two companies. The combined company may incur additional unanticipated costs in the integration of the businesses of Exelon and Constellation. Although Exelon expects that the elimination of certain duplicative costs, as well as the realization of other efficiencies related to the integration of the two businesses, will offset the incremental transaction and merger−related costs over time, the combined company may not achieve this net benefit in the near term, or at all.

Current Exelon shareholders and Constellation stockholders will have a reduced ownership and voting interest after the merger.

Exelon will issue or reserve for issuance approximately 201.9 million shares of Exelon common stock to Constellation stockholders in the merger (including shares of Exelon common stock issuable pursuant to Constellation stock options and other equity−based awards). Based on the number of shares of common stock of Exelon and Constellation outstanding on March 31, 2011, the record date for the two companies' special meetings of shareholders, upon the completion of the merger, current Exelon shareholders and former Constellation stockholders would own approximately 78% and 22% of the outstanding shares of Exelon common stock, respectively, immediately following the consummation of the merger.

Exelon shareholders and Constellation stockholders currently have the right to vote for their respective directors and on other matters affecting their company. When the merger occurs, each Constellation stockholder who receives shares of Exelon common stock will become a shareholder of Exelon with a percentage ownership of the combined company that will be smaller than the shareholder's percentage ownership of Constellation.

Correspondingly, each Exelon shareholder will remain a shareholder of Exelon with a percentage ownership of the combined company that will be smaller than the shareholder's percentage of Exelon prior to the merger. As a result of these reduced ownership percentages, Exelon shareholders will have less voting power in the combined company than they now have with respect to Exelon, and former Constellation stockholders will have less voting power in the combined company than they now have with respect to Constellation.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Exelon, Generation, ComEd and PECO

None.

Table of Contents

ITEM 2. PROPERTIES

Generation

The following table sets forth Generation's owned net electric generating capacity by station at December 31, 2011:

Station (d)	Location	No. of Units	Percent Owned (a)	Primary Fuel Type	Primary Dispatch Type (b)	Net Generation Capacity (MW) (c)
Nuclear						
Braidwood	Braidwood, IL	2		Uranium	Base−load	2,348
Byron	Byron, IL	2		Uranium	Base−load	2,323
Clinton	Clinton, IL	1		Uranium	Base−load	1,067
Dresden	Morris, IL	2		Uranium	Base−load	1,753
LaSalle	Seneca, IL	2		Uranium	Base−load	2,316
Limerick	Limerick Twp., PA	2		Uranium	Base−load	2,312
Oyster Creek	Forked River, NJ	1		Uranium	Base−load	625(e)
Peach Bottom	Peach Bottom Twp., PA	2	50	Uranium	Base−load	1,150(f)
Quad Cities	Cordova, IL	2	75	Uranium	Base−load	1,380(f)
Salem	Hancock's Bridge, NJ	2	42.59	Uranium	Base−load	1,004(f)
Three Mile Island	Londonderry Twp, PA	1		Uranium	Base−load	837
						17,115
Fossil (Steam Turbines)(g)						
Conemaugh	New Florence, PA	2	20.72	Coal	Base−load	352(f)
Eddystone 3, 4	Eddystone, PA	2		Oil/Gas	Intermediate	760
Handley 4, 5	Fort Worth, TX	2		Gas	Peaking	870
Handley 3	Fort Worth, TX	1		Gas	Intermediate	395
Keystone	Shelocta, PA	2	20.99	Coal	Base−load	357(f)
Mountain Creek 6, 7	Dallas, TX	2		Gas	Peaking	240
Mountain Creek 8	Dallas, TX	1		Gas	Intermediate	565
Schuylkill	Philadelphia, PA	1		Oil	Peaking	166
Wolf Hollow 1, 2	Granbury, TX	2		Gas	Intermediate	425
Wolf Hollow 3	Granbury, TX	1		Gas	Intermediate	280
Wyman	Yarmouth, ME	1	5.89	Oil	Intermediate	36(f)
						4,446
Fossil (Combustion Turbines)						
Chester	Chester, PA	3		Oil	Peaking	39
Croydon	Bristol Twp., PA	8		Oil	Peaking	391
Delaware	Philadelphia, PA	4		Oil	Peaking	56
Eddystone	Eddystone, PA	4		Oil	Peaking	60
Falls	Falls Twp., PA	3		Oil	Peaking	51
Framingham	Framingham, MA	3		Oil	Peaking	28
LaPorte	Laporte, TX	4		Gas	Peaking	152
Medway	West Medway, MA	3		Oil/Gas	Peaking	105
Moser	Lower Pottsgrove Twp., PA	3		Oil	Peaking	51
New Boston	South Boston, MA	1		Oil	Peaking	12
Richmond	Philadelphia, PA	2		Oil	Peaking	98
Salem	Hancock's Bridge, NJ	1	42.59	Oil	Peaking	16(f)
Schuylkill	Philadelphia, PA	2		Oil	Peaking	30
Southeast Chicago	Chicago, IL	8		Gas	Peaking	296
Southwark	Philadelphia, PA	4		Oil	Peaking	52
						1,437

Station	Location	No. of Units	Percent Owned [a]	Primary Fuel Type	Primary Dispatch Type [b]	Net Generation Capacity (MW) [c]
Fossil (Internal Combustion/Diesel)						
Conemaugh	New Florence, PA	4	20.72	Oil	Peaking	2[f]
Keystone	Shelocta, PA	4	20.99	Oil	Peaking	2[f]
Schuylkill	Philadelphia, PA	1		Oil	Peaking	3
						7
Hydroelectric and Other Renewables						
AgriWind	Bureau Co., IL	4	99	Wind	Base−load	8[f]
Blue Breezes	Faribault Co., MN	2		Wind	Base−load	3
Bluegrass Ridge	Gentry Co., MO	27	99	Wind	Base−load	56[f]
Brewster	Jackson Co., MN	6	94−99	Wind	Base−load	6[f]
Cassia	Twin Falls Co., ID	14		Wind	Base−load	29
Cisco	Jackson Co., MN	4	99	Wind	Base−load	8[f]
City Solar	Chicago, IL	n.a.		Solar	Base−load	10
Conception	Nodaway Co., MO	24		Wind	Base−load	50
Conowingo	Harford Co., MD	11		Hydroelectric	Base−load	572
Cow Branch	Atchinson Co., MO	24		Wind	Base−load	50
Cowell	Pipestone Co., MN	1	99	Wind	Base−load	2[f]
CP Windfarm	Faribault Co., MN	2		Wind	Base−load	4
Echo 1	Umatilla Co., OR	21	99	Wind	Base−load	34[f]
Echo 2	Morrow Co., OR	10		Wind	Base−load	20
Echo 3	Morrow Co., OR	6	99	Wind	Base−load	10[f]
Exelon Wind 1	Hansford Co., TX	8		Wind	Base−load	10
Exelon Wind 2	Hansford Co., TX	8		Wind	Base−load	10
Exelon Wind 3	Hansford Co., TX	8		Wind	Base−load	10
Exelon Wind 4	Hansford Co., TX	38		Wind	Base−load	80
Exelon Wind 5	Sherman Co., TX	8		Wind	Base−load	10
Exelon Wind 6	Sherman Co., TX	8		Wind	Base−load	10
Exelon Wind 7	Moore Co., TX	8		Wind	Base−load	10
Exelon Wind 8	Moore Co., TX	8		Wind	Base−load	10
Exelon Wind 9	Moore Co., TX	8		Wind	Base−load	10
Exelon Wind 10	Moore Co., TX	8		Wind	Base−load	10
Exelon Wind 11	Moore Co., TX	8		Wind	Base−load	10
Ewington	Jackson Co., MN	10	99	Wind	Base−load	20[f]
Fairless Hills	Falls Twp, PA	2		Landfill Gas	Peaking	60
Greensburg	Kiowa Co., KS	10		Wind	Base−load	13
Harvest	Huron Co., MI	32		Wind	Base−load	53
High Plains	Moore Co., TX	8	99.5	Wind	Base−load	10[f]
Loess Hills	Atchinson Co., MO	4		Wind	Base−load	5
Marshall	Lyon Co., MN	9	98−99	Wind	Base−load	19[f]
Michigan Wind 1	Bingham Twp., MI	46		Wind	Base−load	69
Michigan Wind 2	Bingham Twp., MI	50		Wind	Base−load	90
Mountain Home	Elmore Co., ID	20		Wind	Base−load	40
Muddy Run	Lancaster, PA	8		Hydroelectric	Intermediate	1,070
Norgaard	Lincoln Co., MN	7	99	Wind	Base−load	9[f]
Pennsbury	Falls Twp., PA	2		Landfill Gas	Peaking	6
Threemile Canyon	Morrow Co., OR	6		Wind	Base−load	10

Station	Location	No. of Units	Percent Owned (a)	Primary Fuel Type	Primary Dispatch Type (b)	Net Generation Capacity (MW) (c)
Tuana Springs	Twin Falls Co., ID	8		Wind	Base−load	17
Wolf	Nobles Co., MN	5	99	Wind	Base−load	6(f)
						2,539
Total						25,544

(a) 100%, unless otherwise indicated.
(b) Base−load units are plants that normally operate to take all or part of the minimum continuous load of a system and, consequently, produce electricity at an essentially constant rate. Intermediate units are plants that normally operate to take load of a system during the daytime higher load hours and, consequently, produce electricity by cycling on and off daily. Peaking units consist of lower−efficiency, quick response steam units, gas turbines and diesels normally used during the maximum load periods.
(c) For nuclear stations, capacity reflects the annual mean rating. Fossil stations reflect a summer rating. For wind stations, reflects the name plate capacity.
(d) All nuclear stations are boiling water reactors except Braidwood, Byron, Salem and Three Mile Island, which are pressurized water reactors.
(e) Generation has agreed to permanently cease generation operation at Oyster Creek by December 31, 2019. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.
(f) Net generation capacity is stated at proportionate ownership share.
(g) Excludes Eddystone Generating Station (Eddystone) Unit 2, which is operating pursuant to a reliability−must−run (RMR) agreement with PJM through May 31, 2012. Eddystone Unit 2 will cease operations upon the end of the RMR period. See Note 14 of the Combined Notes to Consolidated Financial Statements for additional information.

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

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

ComEd

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

Transmission and Distribution

ComEd's higher voltage electric transmission lines owned and in service at December 31, 2011 were as follows:

Voltage (Volts)	Circuit Miles
765,000	90
345,000	2,642
138,000	2,237

Table of Contents

ComEd's electric distribution system includes 35,569 circuit miles of overhead lines and 30,408 circuit miles of underground lines.

First Mortgage and Insurance

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

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

PECO

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

Transmission and Distribution

PECO's high voltage electric transmission lines owned and in service at December 31, 2011 were as follows:

Voltage (Volts)	Circuit Miles
500,000	188[a]
230,000	541
138,000	156
69,000	200

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

PECO's electric distribution system includes 12,972 circuit miles of overhead lines and 8,851 circuit miles of underground lines.

Gas

The following table sets forth PECO's natural gas pipeline miles at December 31, 2011:

	Pipeline Miles
Transportation	31
Distribution	6,732
Service piping	4,533
Total	11,296

PECO has an LNG facility located in West Conshohocken, Pennsylvania that has a storage capacity of 1,200 mmcf and a send−out capacity of 157 mmcf/day and a propane−air plant located in

Chester, Pennsylvania, with a tank storage capacity of 1,980,000 gallons and a peaking capability of 25 mmcf/day. In addition, PECO owns 32 natural gas city gate stations and direct pipeline customer delivery points at various locations throughout its gas service territory.

First Mortgage and Insurance

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

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

Exelon

Security Measures

The Registrants have initiated and work to maintain security measures. On a continuing basis, the Registrants evaluate enhanced security measures at certain critical locations, enhanced response and recovery plans, long−term design changes and redundancy measures. Additionally, the energy industry has strategic relationships with governmental authorities to ensure that emergency plans are in place and critical infrastructure vulnerabilities are addressed in order to maintain the reliability of the country's energy systems.

ITEM 3. LEGAL PROCEEDINGS

Exelon, Generation, ComEd and PECO

The Registrants are parties to various lawsuits and regulatory proceedings in the ordinary course of their respective businesses. For information regarding material lawsuits and proceedings, see Notes 2 and 18 of the Combined Notes to Consolidated Financial Statements. Such descriptions are incorporated herein by these references.

ITEM 4. MINE SAFETY DISCLOSURES

Exelon, Generation, ComEd and PECO

Not Applicable to the Registrants.

PART II

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

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

Exelon

Exelon's common stock is listed on the New York Stock Exchange. As of January 31, 2012, there were 663,640,976 shares of common stock outstanding and approximately 125,092 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:

	2011				2010			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$ 45.45	$ 45.27	$ 42.89	$ 43.58	$ 44.49	$ 43.32	$ 45.10	$ 49.88
Low price	39.93	39.51	39.53	39.06	39.05	37.63	37.24	42.97
Close	43.37	42.61	42.84	41.24	41.64	42.58	37.97	43.81
Dividends	0.525	0.525	0.525	0.525	0.525	0.525	0.525	0.525

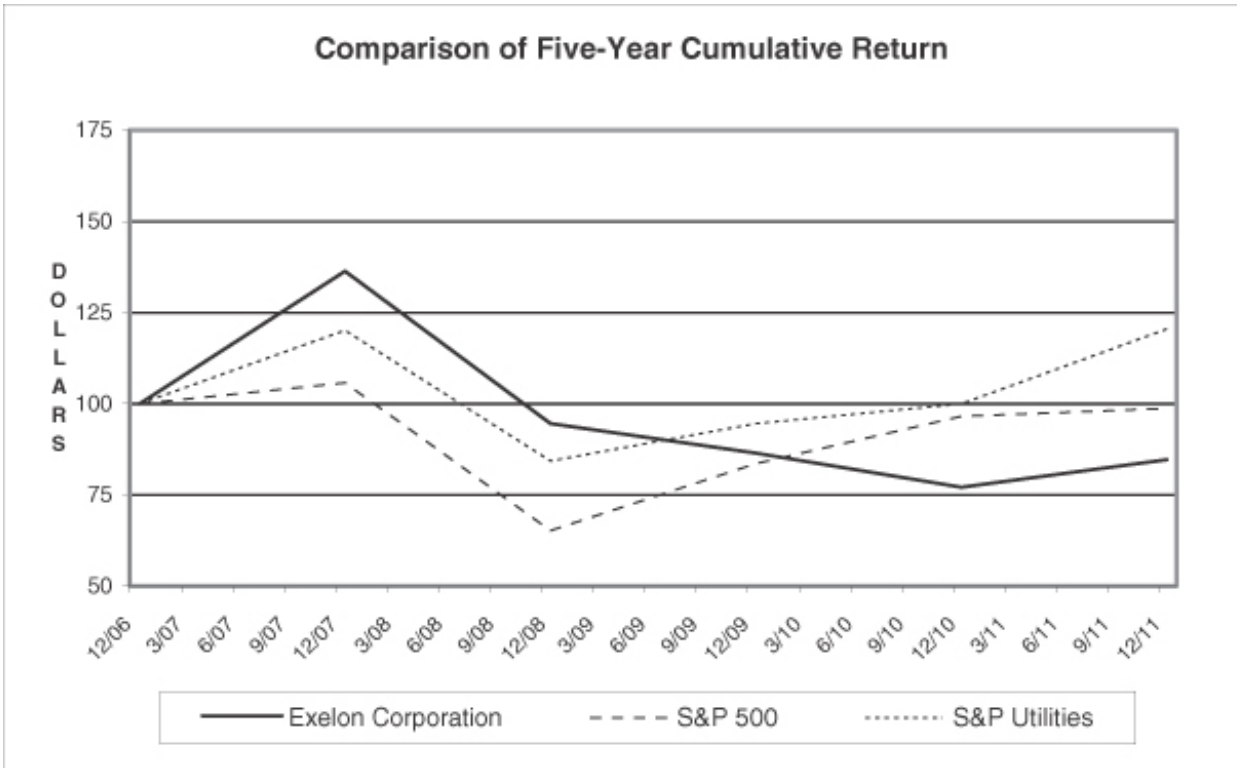
Table of Contents

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 2007 through 2011.

This performance chart assumes:

- $100 invested on December 31, 2006 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,					
	2006	2007	2008	2009	2010	2011
Exelon Corporation	$100.00	$135.06	$94.71	$86.88	$77.86	$85.17
S&P 500	$100.00	$105.48	$66.52	$84.07	$96.71	$98.76
S&P Utilities	$100.00	$119.34	$84.81	$94.83	$99.99	$119.83

Generation

As of January 31, 2012, Exelon indirectly held the entire membership interest in Generation.

ComEd

As of January 31, 2012, there were 127,016,529 outstanding shares of common stock, $12.50 par value, of ComEd, of which 127,002,904 shares were indirectly held by Exelon. At January 31, 2012, in addition to Exelon, there were 240 record holders of ComEd common stock. There is no established market for shares of the common stock of ComEd.

PECO

As of January 31, 2012, there were 170,478,507 outstanding shares of common stock, without par value, of PECO, all of which were indirectly held by Exelon.

Exelon, Generation, ComEd and PECO

Dividends

Under applicable Federal law, Generation, ComEd and PECO can pay dividends only from retained, undistributed or current earnings. A significant loss recorded at Generation, ComEd or PECO 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 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, 2011, such capital was $2.9 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.

At December 31, 2011, Exelon had retained earnings of $10,055 million, including Generation's undistributed earnings of $4,232 million, ComEd's retained earnings of $447 million consisting of retained earnings appropriated for future dividends of $2,086 million, partially offset by $1,639 million of unappropriated retained deficits, and PECO's retained earnings of $559 million.

Table of Contents

The following table sets forth Exelon's quarterly cash dividends per share paid during 2011 and 2010:

	2011				2010			
(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 and PECO's quarterly common dividend payments:

	2011				2010			
(in millions)	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter	4th Quarter	3rd Quarter	2nd Quarter	1st Quarter
Generation	$ 111	$ 61	$ —	$ —	$ 885	$ 206	$ 156	$ 261
ComEd	75	75	75	75	85	75	75	75
PECO	80	84	73	111	46	63	51	64

First Quarter 2012 Dividend. On October 25, 2011, the Exelon Board of Directors declared a first quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

Second Quarter 2012 Dividend. In addition, on January 24, 2012, the Exelon Board of Directors declared a second quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock contingent on the pending merger with Constellation. If the effective date of the merger is after May 15, 2012, the Board of Directors declared a regular quarterly dividend of $0.525 per share on Exelon's common stock, payable on June 8, 2012, to shareholders of record of Exelon at the end of the day on May 15, 2012.

If the effective date of the merger is on or before May 15, 2012, shareholders will receive two separate dividend payments totaling $0.525 per share:

- The first of the dividend payments will be pro−rated, with shareholders of record as of the end of day before the effective date of the merger receiving $0.00583 per share per day for the period from and including February 16, 2012, the day after the record date for the previous dividend, through and including the day before the effective date of the merger. This portion of the dividend will be paid within 30 days after the effective date of the merger.
- The second of the dividend payments will also be pro−rated, with all Exelon shareholders, including the former Constellation shareholders, of record at the end of the day on May 15, 2012, receiving $0.00583 per share per day for the period from and including the effective date of the merger through and including May 15, 2012. This portion of the dividend will be paid on June 8, 2012.

[Table of Contents](#)

ITEM 6. SELECTED FINANCIAL DATA

Exelon

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

	For the Years Ended December 31,				
(In millions, except per share data)	2011	2010	2009	2008	2007
Statement of Operations data:					
Operating revenues	$18,924	$18,644	$17,318	$18,859	$18,916
Operating income	4,480	4,726	4,750	5,299	4,668
Income from continuing operations	$ 2,495	$ 2,563	$ 2,706	$ 2,717	$ 2,726
Income from discontinued operations	—	—	1	20	10
Net income	$ 2,495	$ 2,563	$ 2,707	$ 2,737	$ 2,736
Earnings per average common share (diluted):					
Income from continuing operations	$ 3.75	$ 3.87	$ 4.09	$ 4.10	$ 4.03
Income from discontinued operations	—	—	—	0.03	0.02
Net income	$ 3.75	$ 3.87	$ 4.09	$ 4.13	$ 4.05
Dividends per common share	$ 2.10	$ 2.10	$ 2.10	$ 2.03	$ 1.76
Average shares of common stock outstanding— diluted	665	663	662	662	676

	December 31,				
(In millions)	2011	2010	2009	2008 (a)	2007 (a)(b)
Balance Sheet data:					
Current assets	$ 5,489	$ 6,398	$ 5,441	$ 5,130	$ 4,416
Property, plant and equipment, net	32,570	29,941	27,341	25,813	24,153
Noncurrent regulatory assets	4,839	4,140	4,872	5,940	5,133
Goodwill	2,625	2,625	2,625	2,625	2,625
Other deferred debits and other assets	9,569	9,136	8,901	8,038	8,760
Total assets	$55,092	$52,240	$49,180	$47,546	$ 45,087
Current liabilities	$ 4,989	$ 4,240	$ 4,238	$ 3,811	$ 5,466
Long−term debt, including long−term debt to financing trusts	12,189	12,004	11,385	12,592	11,965
Noncurrent regulatory liabilities	3,771	3,555	3,492	2,520	3,301
Other deferred credits and other liabilities	19,668	18,791	17,338	17,489	14,131
Preferred securities of subsidiary	87	87	87	87	87
Noncontrolling interest	3	3	—	—	—
Shareholders' equity	14,385	13,560	12,640	11,047	10,137
Total liabilities and shareholders' equity	$55,092	$52,240	$49,180	$47,546	$ 45,087

(a) Exelon retrospectively reclassified certain assets and liabilities with respect to option premiums into the mark−to−market net asset and liability accounts to conform to the current year presentation.

(b) Exelon retrospectively reclassified certain assets and liabilities in accordance with the applicable authoritative guidance for offsetting amounts related to qualifying derivative contracts.

Table of Contents

Generation

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

	For the Years Ended December 31,				
(In millions)	2011	2010	2009	2008	2007
Statement of Operations data:					
Operating revenues	$10,308	$10,025	$ 9,703	$10,754	$ 10,749
Operating income	2,876	3,046	3,295	3,994	3,392
Income from continuing operations	$ 1,771	$ 1,972	$ 2,122	$ 2,258	$ 2,025
Income from discontinued operations	—	—	—	20	4
Net income	$ 1,771	$ 1,972	$ 2,122	$ 2,278	$ 2,029

	December 31,				
(In millions)	2011	2010	2009	2008 (a)	2007 (a)(b)
Balance Sheet data:					
Current assets	$ 3,204	$ 3,087	$ 3,360	$ 3,486	$ 2,160
Property, plant and equipment, net	13,475	11,662	9,809	8,907	8,043
Other deferred debits and other assets	10,754	9,785	9,237	7,691	8,044
Total assets	$27,433	$24,534	$22,406	$20,084	$ 18,247
Current liabilities	$ 2,144	$ 1,843	$ 2,262	$ 2,168	$ 1,917
Long−term debt	3,674	3,676	2,967	2,502	2,513
Other deferred credits and other liabilities	12,907	11,838	10,385	8,848	9,447
Noncontrolling interest	5	5	2	1	1
Member's equity	8,703	7,172	6,790	6,565	4,369
Total liabilities and member's equity	$27,433	$24,534	$22,406	$20,084	$ 18,247

(a) Generation retrospectively reclassified certain assets and liabilities with respect to option premiums into the mark−to−market net asset and liability accounts to conform with the current year presentation.

(b) Generation reclassified certain assets and liabilities in accordance with the applicable authoritative guidance for offsetting amounts related to qualifying derivative contracts.

ComEd

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

	For the Years Ended December 31,				
(In millions)	2011	2010	2009	2008	2007
Statement of Operations data:					
Operating revenues	$ 6,056	$ 6,204	$ 5,774	$ 6,136	$ 6,104
Operating income	982	1,056	843	667	512
Net income	416	337	374	201	165

	December 31,				
(In millions)	2011	2010	2009	2008	2007
Balance Sheet data:					
Current assets	$ 2,106	$ 2,151	$ 1,579	$ 1,309	$ 1,241
Property, plant and equipment, net	13,121	12,578	12,125	11,655	11,127
Goodwill	2,625	2,625	2,625	2,625	2,625
Noncurrent regulatory assets	796	947	1,096	858	503
Other deferred debits and other assets	4,005	3,351	3,272	2,790	3,880
Total assets	$22,653	$21,652	$20,697	$19,237	$19,376
Current liabilities	$ 1,946	$ 2,134	$ 1,597	$ 1,153	$ 1,712
Long−term debt, including long−term debt to financing trusts	5,421	4,860	4,704	4,915	4,384
Noncurrent regulatory liabilities	3,167	3,137	3,145	2,440	3,447
Other deferred credits and other liabilities	5,082	4,611	4,369	3,994	3,305
Shareholders' equity	7,037	6,910	6,882	6,735	6,528
Total liabilities and shareholders' equity	$22,653	$21,652	$20,697	$19,237	$19,376

[Table of Contents](#)

PECO

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

	For the Years Ended December 31,				
(In millions)	2011	2010	2009	2008	2007
Statement of Operations data:					
Operating revenues	$3,720	$5,519	$5,311	$5,567	$5,613
Operating income	655	661	697	699	947
Net income	389	324	353	325	507
Net income on common stock	385	320	349	321	503

	December 31,				
(In millions)	2011	2010	2009	2008	2007
Balance Sheet data:					
Current assets	$1,216	$1,670	$1,006	$ 819	$ 800
Property, plant and equipment, net	5,874	5,620	5,297	5,074	4,842
Noncurrent regulatory assets	1,243	968	1,834	2,597	3,273
Other deferred debits and other assets	823	727	882	679	895
Total assets	$9,156	$8,985	$9,019	$9,169	$9,810
Current liabilities	$1,126	$1,163	$ 939	$ 981	$1,516
Long−term debt, including long−term debt to financing trusts	1,781	2,156	2,405	2,960	2,866
Noncurrent regulatory liabilities	604	418	317	49	250
Other deferred credits and other liabilities	2,620	2,278	2,706	2,910	3,068
Preferred securities	87	87	87	87	87
Shareholders' equity	2,938	2,883	2,565	2,182	2,023
Total liabilities and shareholders' equity	$9,156	$8,985	$9,019	$9,169	$9,810

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

Exelon

General

Exelon, a utility services holding company, operates through the following principal subsidiaries each of which is treated as a reportable segment:

- *Generation,* whose business consists of owned and contracted electric generating facilities, wholesale energy marketing operations and competitive retail sales operations.
- *ComEd,* whose business consists of the purchase and regulated retail sale of electricity and the provision of transmission and distribution 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 transmission and distribution services in southeastern Pennsylvania, including the City of Philadelphia, as well as the purchase and regulated retail sale of natural gas and the provision of distribution services in the Pennsylvania counties surrounding the City of Philadelphia.

See Note 20 of the Combined Notes to Consolidated Financial Statements for segment information.

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

Exelon Corporation

Executive Overview

Financial Results. All amounts presented below are before the impact of income taxes, except as noted.

Exelon's net income was $2,495 million for the year ended December 31, 2011 as compared to $2,563 million for the year ended December 31, 2010, and diluted earnings per average common share were $3.75 for the year ended December 31, 2011 as compared to $3.87 for the year ended December 31, 2010.

Operating revenue net of purchased power and fuel expense, which is a non−GAAP measure discussed below, decreased by $413 million primarily related to a decrease in CTC recoveries at PECO of $995 million as a result of the end of the transition period on December 31, 2010. This impact on Exelon's operating income was partially offset by decreased CTC amortization expense discussed below. Mark−to−market losses of $288 million in 2011 from Generation's hedging activities compared to $86 million in mark−to−market gains in 2010 also had an unfavorable impact on Generation's operating results. In addition, Generation's operating revenue net of purchased power and fuel expense decreased by $534 million in the Midwest due to decreased realized margins in 2011 for volumes previously sold under the 2006 ComEd auction contracts and increased nuclear fuel costs. Partially offsetting these unfavorable impacts were increased operating revenues net of purchased power and fuel expense at Generation of $847 million in the Mid−Atlantic due to increased margins on volumes previously sold under Generation's PPA with PECO, which expired on December 31, 2010, and increased operating revenues net of purchased power and fuel expense of $201 million in the South and West primarily driven by the performance of Exelon's generating units during extreme weather events that occurred in Texas in February and August of 2011. Operating revenue net of purchased power and fuel expense in the South and West was also impacted favorably by additional revenues from Exelon Wind, which was acquired in December 2010, and higher realized margins due to overall favorable market conditions. The decrease in revenue net of purchased power and fuel expense was also partially offset by the 2010 impact of the impairment charge of certain emission allowances, as well as compensation under the reliability−must−run rate schedule received in 2011. ComEd's and PECO's operating revenues net of purchased power and fuel expense increased by $89 million and $155 million, respectively, as a result of improved pricing primarily due to the new electric distribution rates effective June 1, 2011 at ComEd and new electric and natural gas distribution rates effective January 1, 2011 at PECO. ComEd's operating revenues also increased by $29 million as a result of increased ComEd distribution revenue pursuant to EIMA, which became effective in the fourth quarter of 2011.

Operating and maintenance expense increased by $596 million in 2011 primarily as a result of increased labor, other benefits, contracting and materials expenses of $241 million, including Exelon Wind, $88 million of costs related to the acquisitions of Wolf Hollow, Antelope Valley and the proposed merger with Constellation and a $74 million increase in nuclear refueling outage costs, including the co−owned Salem plant. Exelon's results were also affected by a $37 million increase in uncollectible accounts expense at ComEd, principally due to the approval of the recovery rider mechanism by the ICC in 2010. The increase was also attributable to higher storm costs in the ComEd and PECO service territories of $70 million and $13 million, respectively, which were partially offset at ComEd by a credit of $55 million, net of amortization, for the allowed recovery of certain 2011 storm costs pursuant to EIMA. These costs were partially offset by one−time net benefits of $32 million to re−establish plant balances and to recover previously incurred costs related to Exelon's 2009 restructuring plan pursuant to the 2010 ComEd Rate Case order recorded in the second quarter of 2011.

Depreciation and amortization expense decreased by $740 million primarily due to a decrease in CTC amortization expense at PECO of $885 million resulting from the end of the transition period on December 31, 2010, partially offset by increased depreciation expense primarily due to additional plant placed in service and the acquisition of Exelon Wind.

Exelon's results were favorably impacted by decreased interest expense of $91 million primarily due to the impact of the 2010 remeasurement of uncertain income tax positions related to the 1999 sale of ComEd's fossil generating assets and CTCs collected by PECO, which resulted in interest expense of $59 million and $36 million, respectively, in 2010. In addition, in 2011, Exelon recorded interest income and tax benefits of $46 million, net of tax including the impact on the manufacturer's deduction, due to the 2011 NDT fund special transfer tax deduction. The decrease in interest expense was partially offset by higher interest expense at Generation and ComEd due to higher outstanding debt balances. Exelon's results were also significantly affected by unrealized losses on NDT funds of $4 million in 2011 (compared to unrealized gains of $104 million in 2010) for Non−Regulatory Agreement Units as a result of unfavorable market performance.

Exelon's results for the year ended December 31, 2011 were favorably impacted by certain prior year income tax−related matters. In 2010, Exelon recorded a $65 million (after−tax) charge to income tax expense as a result of health care legislation passed in March 2010 that includes a provision that reduces the deductibility of retiree prescription drug benefits for Federal income tax purposes. This amount was partially offset by a non−cash charge of $29 million (after−tax) recorded at Exelon in 2011 for the remeasurement of deferred taxes at higher corporate tax rates pursuant to the Illinois tax rate change legislation.

Table of Contents

For further detail regarding the financial results for the years ended December 31, 2011 and 2010, 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, 2011 were $2,763 million, or $4.16 per diluted share, compared with adjusted (non−GAAP) operating earnings of $2,689 million, or $4.06 per diluted share, for the same period in 2010. 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, 2011 as compared to 2010:

	December 31,			
	2011		2010	
(All amounts after tax; in millions, except per share amounts)		**Earnings per Diluted Share**		**Earnings per Diluted Share**
Net Income	$2,495	$ 3.75	$2,563	$ 3.87
Mark−to−Market Impact of Economic Hedging Activities [(a)]	174	0.27	(52)	(0.08)
Unrealized (Gains) Losses Related to NDT Fund Investments [(b)]	1	—	(52)	(0.08)
Retirement of Fossil Generating Units [(c)]	33	0.05	50	0.08
Asset Retirement Obligation Updates [(d)]	16	0.02	(7)	(0.01)
Constellation Acquisition Costs [(e)]	46	0.07	—	—
Other Acquisition Costs [(f)]	5	0.01	7	0.01
Non−Cash Charge Resulting From Illinois Tax Rate Change Legislation [(g)]	29	0.04	—	—
Wolf Hollow Acquisition [(h)]	(23)	(0.03)	—	—
Recovery of Costs Pursuant to Distribution Rate Case Order [(i)]	(17)	(0.03)	—	—
Non−Cash Remeasurement of Deferred Income Taxes [(j)]	4	0.01	—	—
Illinois Settlement Legislation [(k)]	—	—	13	0.02
Impairment of Certain Emissions Allowances [(l)]	—	—	35	0.05
City of Chicago Settlement with ComEd [(m)]	—	—	2	—
Non−Cash Charge Resulting From Health Care Legislation [(n)]	—	—	65	0.10
Non−Cash Remeasurement of Income Tax Uncertainties and Reassessment of State Deferred Income Taxes [(o)]	—	—	65	0.10
Adjusted (non−GAAP) Operating Earnings	$2,763	$ 4.16	$2,689	$ 4.06

(a) Reflects the impact of (gains) losses for the years ended December 31, 2011 and 2010, respectively, on Generation's economic hedging activities (net of taxes $114 million and $(34) million, respectively). See Note 9 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, 2011 and 2010, respectively, on Generation's NDT fund investments for Non−Regulatory Agreement Units (net of taxes of $(3) million and $(50) million, respectively). See Note 12 of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.
(c) Primarily reflects accelerated depreciation expense for the years ended December 31, 2011 and 2010 (net of taxes of $21 million and $32 million, respectively) associated with the planned retirement of four generating units, two of which were retired on May 31, 2011. Beginning June 1, 2011, reflects the net loss attributable to the remaining two units, which includes compensation for operating the units past their planned May 31, 2011 retirement date under a FERC−approved reliability−must−run rate schedule. See Note 14 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, 2011 and 2010, respectively, primarily related to the reduction in PECO's asset retirement obligation in 2011 (net of taxes of $(1) million), an increase in Generation's Zion's decommissioning obligation for spent nuclear fuel at Zion in 2011 (net of taxes of $11 million) and the reduction in the asset retirement obligations at ComEd and PECO in 2010 (net of taxes of $(4) million).
(e) Reflects certain costs incurred in the year ended December 31, 2011 associated with Exelon's proposed acquisition of Constellation (net of taxes of $31 million). See Note 3 of the Combined Notes to the Consolidated Financial Statements for additional information.
(f) Reflects certain costs incurred in the years ended December 31, 2011 and 2010, respectively, associated with Exelon's acquisitions of Exelon Wind in 2010 (net of taxes of $4 million) and Antelope Valley in 2011 (net of taxes of $3 million). See Note 3 of the Combined Notes to Consolidated Financial Statements for additional information.
(g) Reflects a one−time, non−cash charge to remeasure deferred taxes at higher corporate tax rates pursuant to the Illinois tax rate change legislation. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.
(h) 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 3 of the Combined Notes to the Consolidated Financial Statements for additional information.
(i) 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 2 of the Combined Notes to the Consolidated Financial Statements for additional information.
(j) Reflects the non−cash impacts of the annual remeasurement of state deferred income taxes to reflect revised estimates of state apportionments. See Note 11 of the Combined Notes to the Consolidated Financial Statements for additional detail related to the impact of the Illinois tax rate change legislation.
(k) Reflects credits issued by Generation and ComEd in 2010 as a result of the Illinois Settlement Legislation (net of taxes of $9 million). See Note 2 of the Combined Notes to the Consolidated Financial Statements for additional detail related to Generation's and ComEd's rate relief commitments.
(l) Reflects the impairment of certain SO2 emissions allowances in 2010 as a result of declining market prices following the release of the EPA's proposed Transport Rule (net of taxes of $22 million). See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.
(m) Reflects costs associated with ComEd's 2007 settlement agreement with the City of Chicago (net of taxes of $1).
(n) Reflects a non−cash charge to income taxes related to the passage of Federal health care legislation, which includes a provision that reduces the deductibility, for Federal income tax purposes, of retiree prescription drug benefits for Federal income tax purposes to the extent they are reimbursed under Medicare Part D. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail related to the impact of the health care legislation.
(o) Reflects the impact of remeasurements of income tax uncertainties. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional detail.

Outlook for 2012 and Beyond.

Acquisitions

Proposed Merger with Constellation. On April 28, 2011, Exelon and Constellation announced that they signed an agreement and plan of merger to combine the two companies in a stock−for−stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's closing share price on April 27, 2011, Constellation shareholders would receive $7.9 billion in total equity value. The resulting company will retain the Exelon name and be headquartered in Chicago. The transaction requires approval by the shareholders of both Exelon and Constellation. Completion of the transaction is also conditioned upon review of the transaction by the U.S. Department of Justice (DOJ) and approval by the FERC, NRC, Maryland Public Service Commission (MDPSC), the New York Public Service Commission (NYPSC), the Public Utility Commission of Texas (PUCT), and other state and federal regulatory bodies. As of February 9, 2012, Exelon and Constellation have received approval of the transaction from the shareholders of Exelon and Constellation, DOJ, PUCT and the NYPSC. Exelon and Constellation are awaiting final approval of the transaction from the MDPSC, FERC and NRC.

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 New York ISO from September 2007 through December 2008. Exelon continues to evaluate the matter in order to make an assessment regarding (1) the likely outcome of the investigation and (2) whether the ultimate resolution of the investigation will be material to the results of operations, cash flows, or financial condition of Constellation before the merger or Exelon after the merger. Absent any delay in the FERC approval process, the companies anticipate closing the transaction in the first quarter of 2012.

Associated with certain of the regulatory approvals required for the merger, the companies have proposed to divest three Constellation generating stations located in PJM, which is the only market where there is a material overlap of generation owned by both companies. 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. In October 2011, Exelon and Constellation reached a settlement with the PJM Independent Market Monitor, who had previously raised market power concerns regarding the merger. The settlement contains a number of commitments by the merged company, including limiting the universe of potential buyers of the divested assets to entities without significant market shares in the relevant PJM markets. The settlement also includes assurances about how the merged company will bid its units into the PJM markets. The proposed divestiture and the settlement with the PJM Market Monitor were filed with FERC and the MDPSC and are included in its decision to issue a final order approving the merger.

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 pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon and Constellation have proposed a package of benefits to BGE customers, the City of Baltimore and the state of Maryland, which results in a direct investment in the state of Maryland of more than $1 billion. This investment includes capital projects including development of new renewable and gas−fired generation in Maryland, representing a substantial portion of the investment.

In addition, in January 2012, Exelon and Constellation reached an agreement with Electricite de France (EDF) under which EDF has withdrawn its opposition to the Exelon−Constellation merger. The terms address Constellation Energy Nuclear Group (CENG), a joint venture between Constellation and EDF that owns and operates three nuclear facilities with 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 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 is disclosed and sought rescission of the proposed merger. During the third quarter, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. The settlement is subject to court approval.

Through December 31, 2011, Exelon has incurred approximately $77 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. Exelon currently estimates the total costs directly related to closing the transaction will be approximately $150 million, which include financial advisor, consultant, legal and SEC registration fees. In addition, Exelon estimates approximately $500 million of additional integration costs, primarily to be incurred in 2012 and 2013. Such costs are expected to be partially offset by projected merger−related synergies in 2012 and fully offset in 2013 and beyond. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation or a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon. The acquisition is anticipated to be break−even to Exelon's adjusted earnings in 2012 and is expected to be accretive to earnings in 2013.

Acquisition of Antelope Valley Solar Ranch One. On September 30, 2011, Generation announced its acquisition of 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. Construction has started, with the first portion of the site expected to come online in late 2012 and full operation planned for late 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 homes on average per year. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020, a business and environmental strategy to eliminate the equivalent of Exelon's 2001 carbon footprint. 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 $713 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 $1.36 billion to be accretive to earnings beginning in 2013 and cash flow accretive starting in 2013. The project is value accretive, and will have stable earnings and cash flow profiles due to the PPA.

Acquisition of Wolf Hollow Generating Station. On August 24, 2011, Generation completed the acquisition of the equity interest of Wolf Hollow, LLC (Wolf Hollow), a combined−cycle natural gas−fired power plant in north Texas, pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. The acquisition builds on the Exelon commitment to clean energy as part of Exelon 2020. Generation recognized a $36 million bargain purchase gain (i.e., negative goodwill) as part of the transaction. The gain was included within other, net in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income. In connection with the acquisition, Generation terminated and settled its long−term PPA with Wolf Hollow; resulting in a gain of approximately $6 million, which is included within Operating Revenues (Other Revenue) in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. In addition to eliminating the existing power purchase agreement, Exelon expects the transaction will be accretive to free cash flow beginning in 2012. The transaction also creates long−term value for Exelon by adding an efficient combined−cycle natural gas−fired plant to Exelon's fleet in ERCOT.

Acquisition of Exelon Wind. In December 2010, Generation acquired all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), a leading operator and developer of wind power, for approximately $893 million in cash. Generation acquired 735 MWs of installed, operating wind capacity located in eight states. Approximately 75% of the operating portfolio's expected output is already sold under long−term power purchase arrangements. Additionally, Generation will pay up to $40 million related to three projects with a capacity of 230 MWs which are currently in advanced stages of development, contingent upon meeting certain contractual commitments related to the commencement of construction of each project. This contingent consideration was valued at $32 million, of which approximately $16 million was paid during 2011. As a result, total consideration recorded for the Exelon Wind acquisition was $925 million. The acquisition currently provides incremental earnings, provides cash flows starting in 2013 and is a key part of Exelon 2020.

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. Prior to the earthquake and tsunami in Japan, the NRC and licensees had been evaluating seismic risk in relation to the design basis of plants and whether additional regulatory action was required. In December 2011, the Commission directed the NRC staff to inform the Commissioners' assistants of its plans for closing out the seismic risk issues previously under review and addressing the interdependency between those issues and the seismic risk recommendations identified in the report of the NRC Near−Term Task Force on the Fukushima Daiichi Accident (Task Force) (discussed in more detail below). In January 2012, the NRC released an updated seismic risk model that plant operators must use in performing the seismic reevaluations recommended by the Task Force.

The NRC has received various petitions from individuals and citizen groups regarding Mark I and II containment systems and requesting that actions be taken in response to the events in Japan. The NRC has either denied the petitions or acknowledged acceptance of the petitions as the subject of ongoing NRC staff and/or Task Force reviews of the Fukushima Daiichi accident. These petitions could affect Dresden, Quad Cities, Oyster Creek and Peach Bottom stations (Mark I containment designs) and LaSalle and Limerick stations (Mark II containment designs).

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 report is the first step in a systematic review that the NRC is conducting. 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 report includes recommendations to the NRC in three primary areas: 1) the overall structure and philosophy of the NRC's regulatory framework; 2) specific design requirements for the nuclear units; and 3) emergency preparedness. During the fourth quarter of 2011, as directed by the Commission, the NRC staff issued its recommendations for prioritizing and implementing the Task Force recommendations and an implementation schedule. Of note, 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. The NRC staff evaluated the potential and relative safety enhancements to be realized from each recommendation and, based on that evaluation, classified the recommendations as falling in three tiers: Tier 1, reflecting near term recommendations to be initiated without unnecessary delay; Tier 2, reflecting recommendations to be deferred pending receipt of additional information, completion of Tier 1 activities, or the availability of resources; and Tier 3, reflecting recommendations to be deferred pending an additional nine month review by the NRC staff. The near term recommendations falling in Tier 1 address seismic and flooding risks, coping with extended loss of power in a station blackout, protecting and increasing the amount of backup equipment, reliable hardened vents for Mark I and Mark II containment, enhancing procedures to address severe accidents and emergency planning, and enhancing spent fuel instrumentation. As instructed by the Commission, the NRC staff also identified additional issues not considered by the Task Force that may, in the staff's assessment, warrant regulatory action. Among the additional issues identified are filtration of containment vents and the transfer of spent fuel to dry cask storage. The staff committed to provide an update on its evaluation of the additional issues within nine months. For each of the recommendations and additional issues, the NRC staff's proposed schedule provides for stakeholder input prior to taking regulatory action.

In December 2011, the Commission approved the staff's prioritization and implementation recommendations subject to a number of conditions. Specifically, among other things, the Commission advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability and to include filtration of containment vents with the Tier 1 review of Mark I and II containments, and encouraged the staff to create requirements based on a performance−based system which allows for flexible approaches and the ability to address a diverse range of site−specific circumstances and conditions and "strive to complete and implement the lessons learned from the Fukushima accident within five years – by 2016." The NRC and staff's next steps are to obtain stakeholder input and issue specific requirements associated with the prioritized recommendations. The requirements for the majority of the Tier 1 recommendations are anticipated to be received in the first quarter of 2012 with the requirements for the remaining Tier 1 recommendations following in 2014 and 2016.

Generation is assessing the impacts of the NRC staff's evaluations and the Commission's approval of the recommendations, both from an operational and a financial impact standpoint. Until the specific requirements for each recommendation are established after obtaining stakeholder input, Generation is unable to determine with specificity the impact the recommendations may have on its nuclear units. However, Generation will continue to engage in nuclear industry assessments and actions.

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. However, as noted above, the NRC staff identified the transfer of spent fuel to dry cask storage as an additional issue to be evaluated by the NRC staff over a nine month period. The facts surrounding what happened at the Fukushima Daiichi Nuclear Power Station, including the nature and extent of damages, the underlying causes of the situation, and the degree to which these factors apply to Generation's nuclear generating facilities, are still under investigation, and will be for some time. Although the NRC staff's reports to the Commission and the Commission's approval of the recommendations and instructions to the NRC staff provide clarity with respect to issues that will be subject to regulatory review and action, the nature and degree of actions that will be required of Generation are still unknown and will be determined through the regulatory process after allowing for stakeholder input. As a result, Exelon and Generation are unable to conclude, at this time, to what extent any actions to comply with the requirements will impact their future results of operations, financial positions and cash flows. See Item 1A. Risk Factors, for further discussion of the risk factors.

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. The nuclear industry has already taken specific steps to respond. Generation has completed actions requested by the Institute of Nuclear Power Operations (INPO), which included tests that verified its emergency equipment is available and functional, walk−downs on its procedures related to critical safety equipment, confirmation of event response procedures and readiness to protect the spent fuel pool, and verification of 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.

Generation's plan for increasing the output through uprates of its nuclear generating stations has not changed as a result of the situation in Japan. However, Generation will continue to monitor NRC directives and guidance that may impact the uprates and, as it has in the past, evaluate each project at the appropriate time and cancel or defer any uprate project that is not considered economical, whether due to energy prices, potential increased regulation, or other factors.

Economic and Market Conditions

Exelon has exposure to various market and financial risks, including the risk of price fluctuations in the wholesale power markets. Wholesale 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 wholesale market prices that Generation's power plants can obtain for their output, (2) the rate of expansion of subsidized low carbon generation such as wind energy 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) regulatory and legislative actions, such as the U.S. EPA's Cross−State Air Pollution Rule (CSAPR) and U.S. EPA's Mercury and Air Toxics Standards (MATS). See *Environmental Matters* section below for further detail on CSAPR and the MATS.

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 power prices, which results in a reduction in Exelon's revenues.

The market price for electricity is also affected by changes in the demand for electricity. Poor economic conditions, milder than normal weather and the growth of energy efficiency and demand response programs can depress demand. The result is that higher−cost generating resources do not run as frequently, putting downward pressure on market prices for electricity and/or capacity. The continued sluggish economy in the United States has led to a decline in demand for electricity. ComEd is projecting load demand to remain essentially flat in 2012 compared to 2011, while PECO is projecting a decline of 5.4% in 2012 compared to 2011 primarily due to the anticipated closing of three oil refineries in its service territory.

Since September 30, 2011, natural gas prices for 2013 and 2014 have declined significantly; reflecting strong natural gas production and significantly warmer than normal weather so far this winter, as well as generally lowered expectations for gas demand and economic growth rates. Wholesale power prices have likewise decreased in response in part to the lower gas prices, and to the late December 2011 judicial stay of the EPA's CSAPR and various other market factors.

Exelon has a policy to hedge commodity risk on a ratable basis over three−year periods, which is intended to reduce the near−term financial impact of market price volatility. As of December 31, 2011, the percentage of expected generation hedged was 88%−91%, 61%−64% and 32%−35% for 2012, 2013 and 2014, respectively.

Exelon also 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, 2011, approximately 35%, or $2.7 billion, of the Registrants' available credit facilities were with European banks. The credit facilities include $7.7 billion in aggregate total commitments of which $6.8 billion was available as of December 31, 2011. There were no borrowings under the Registrants' credit facilities as of December 31, 2011. See Note 10 of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Exelon routinely reviews its hedging policy, operating and capital costs, capital spending plans, 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. Based on the results of these assessments, Exelon management believes it is able to respond to changing market conditions in a manner that ensures reliable and safe service for our customers and sufficient liquidity to operate our businesses.

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 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 2012 and 2013. 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. Generation currently hedges commodity risk on a ratable basis over the three years leading to the spot market. As of December 31, 2011, the percentage of expected generation hedged was 88%−91%, 61%−64% and 32%−35% for 2012, 2013 and 2014, 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 cash flow hedges, other derivatives and certain non−derivative contracts including sales to ComEd and PECO 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. The expiration of the PPA with PECO at the end of 2010 has resulted in increases in margins earned by Generation in 2011 for the portion of Generation's electricity portfolio previously sold to PECO under the PPA; however the ultimate impact of entering into new power supply contracts under Generation's three−year ratable hedging program to replace the PPA will depend on a number of factors, including future wholesale market prices, capacity markets, energy demand and the effects of any new applicable Pennsylvania laws and or rules and regulations promulgated by the PAPUC.

Generation procures coal 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 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 55% of Generation's uranium concentrate requirements from 2012 through 2016 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. Generation uses long−term contracts and financial instruments such as over−the−counter and exchange−traded instruments to mitigate price risk associated with certain commodity price exposures. Both ComEd and PECO 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 has announced a series of planned power uprates across its nuclear fleet that would result in between 1,175 and 1,300 MWs at an overnight cost of approximately $3.3 billion in 2011 dollars, of which approximately $800 million has been spent through December 31, 2011. Overnight costs do not include financing costs or cost escalation. Using proven technologies, the projects take advantage of new production and measurement technologies, new materials and learning from a half−century of nuclear power operations. Uprate projects, representing approximately 75% of the planned uprate MWs, are underway at the Limerick, TMI and Peach Bottom nuclear stations in Pennsylvania and the Byron, Braidwood, Dresden, LaSalle and Quad Cities plants in Illinois. The remaining uprate MWs will come from additional projects across Generation's nuclear fleet beginning in 2012 and ending in 2017. At 1,300 nuclear−generated MWs, the uprates would displace 6 million metric tons of carbon emissions annually that would otherwise come from burning fossil fuels. The uprates are being undertaken pursuant to an organized, strategically sequenced implementation plan. The implementation effort includes a periodic review and refinement of the project in light of changing market conditions. The amount of expenditures to implement the plan ultimately 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. The ability to implement several projects requires the successful resolution of various technical issues. The resolution of these issues may affect the timing and amount of the power increases associated with the power uprate initiative. Through December 31, 2011, Generation has added 240 MWs of nuclear generation through its uprate program.

Transmission Development Project. Exelon, Electric Transmission America, LLC (ETA) and AEP Transmission Holding Company, LLC (AEP) are working collaboratively to develop a 420−mile 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 ETA (37.5%), AEP (37.5%) and RTD (25%). Exelon Transmission Company, LLC and ETA each own 50% of RTD. During December 2011, RITELine Illinois, RITELine Indiana and RTD received capital contributions of $2 million, $2 million and $1 million respectively. Funding was provided to each company based upon the aforementioned ownership structure. 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 will depend on a number of factors, including RTO requirements, state siting requirements, routing of the line, and equipment and commodity costs. The project will be built in stages over three to four years, likely between 2015 and 2018, and is subject to FERC, PJM and state approvals. Significant funding for this project is not expected to occur until 2014, with most of the funding expected in 2015−2017.

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 9.93%, 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 11.43%. 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.

Utility Infrastructure. During the fourth quarter of 2011, EIMA was enacted in Illinois, which provides for ComEd to invest an additional $2.6 billion over a ten−year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre−established distribution formula rate tariff.

In 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan, representing an investment of up to a total of $650 million, including its $200 million SGIG, on its smart grid and smart meter infrastructure. See the *Regulatory and Legislative Matters* section below and Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on the utility infrastructure projects.

Liquidity and Cost Management

Pension Plan Funding. In January 2011, Exelon contributed $2.1 billion to its pension plans which, along with other factors, increased the funded status of the Exelon pension plans to 83% at December 31, 2011 from 71% at December 31, 2010. This contribution creates flexibility around the timing of future expected minimum contributions, decreases future pension costs, and allows Exelon to further pursue its liability hedge strategy in order to reduce the volatility of its pension assets relative to its pension liabilities.

Financing Activities. On January 18, 2011, ComEd issued $600 million of 1.625% First Mortgage Bonds due January 15, 2014. The net proceeds of the bonds were used as an interim source of liquidity for the January 2011 contribution to Exelon−sponsored pension plans in which ComEd participates. ComEd anticipates receiving tax refunds as a result of both the pension contribution and the Tax Relief Act of 2010 allowing for 100% bonus depreciation deductions in 2011 and 2012. As a result, the immediate use of the net proceeds to fund the planned contribution will allow those future cash receipts to be available to fund capital investment and for general corporate purposes.

On September 7, 2011, ComEd issued $250 million of 1.95% First Mortgage Bonds due September 1, 2016 and $350 million of 3.40% First Mortgage Bonds due September 1, 2021. The majority of the net proceeds of the bonds was used to refinance $191 million of ComEd's variable rate tax−exempt bonds on October 12, 2011 and $345 million of ComEd's 5.40% First Mortgage Bonds due December 15, 2011. The remainder of the net proceeds were used to fund other general corporate purposes.

Credit Facilities. On March 23, 2011, Exelon Corporate, Generation and PECO replaced their unsecured revolving credit facilities with new facilities with aggregate bank commitments of $500 million, $5.3 billion and $600 million, respectively. Although the covenants are largely the same as the prior facilities, the new facilities have higher borrowing costs, reflecting current market pricing. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding those costs.

ComEd's $1.0 billion unsecured revolving credit facility expires on March 25, 2013 unless extended in accordance with terms. ComEd plans to renew or replace the credit facility in 2012. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facility terms.

On October 21, 2011, Generation, ComEd and PECO replaced their expiring minority and community bank credit facility agreements with new minority and community bank credit facility agreements in the amounts of $50 million, $34 million and $34 million, respectively. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding the credit facilities.

Cost Management. Exelon is committed to operating its businesses responsibly and managing its operating and capital costs in a manner that serves its customers and produces value for its shareholders. Exelon is also committed to an ongoing strategy to make itself more effective, efficient and innovative. Exelon is committed to maintaining a cost control focus and continues to analyze cost trends to identify future cost savings opportunities and implement more planning and performance−measurement tools to allow it to better identify areas for sustainable productivity improvements and cost reductions across the Registrants.

Environmental Matters

Exelon 2020. In 2008, Exelon announced a comprehensive business and environmental strategic plan, which details an enterprise−wide strategy and a wide range of initiatives being pursued by Exelon to reduce, offset, or displace more than 15 million metric tons of GHG emissions per year by 2020 (from 2001 levels). Exelon has incorporated Exelon 2020 into its overall business plans, and as further legislation and regulation imposing requirements on emissions of air pollutants are promulgated, its emissions reduction efforts will position Exelon to benefit from the long−term positive impact of the requirements on capacity and energy prices while minimizing the impact of costs of compliance on Exelon's operations, cash flows or financial position.

Environmental Legislative and Regulatory Developments

Exelon supports the promulgation of environmental regulation 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 its low emission generation portfolio, Generation will not be significantly directly affected by these regulations, representing a competitive advantage for Generation relative to electric generators that are more reliant on fossil−fuel plants. Various bills have been introduced in the U.S. House of Representatives that would prohibit or impede the U.S. EPA's rulemaking efforts. The timing of the consideration of such legislation is unknown.

Air. Beginning with the CSAPR, the air requirements are expected to be implemented through a series of increasingly stringent regulations relating to conventional air pollutants (e.g., NO_x, SO_2 and particulate matter) as well as HAPs (e.g., acid gases, mercury and other heavy metals). It is expected that the U.S. EPA will complete a review of NAAQS in the 2012 – 2013 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide and lead. This review will likely result in more stringent emissions limits on fossil−fuel fired electric generating stations. There is opposition among fossil fuel−fuel fired generation owners to the potential stringency and timing of these air regulations, and the House Commerce and Energy Committee and several of its subcommittees have held a number of hearings on these issues.

On July 7, 2011, the U.S. EPA published a final rule known as CSAPR. The CSAPR requires 27 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. On October 14, 2011, the EPA proposed for public comment certain technical corrections to CSAPR, including correction of data errors in determining generation unit allowances and state allowance budgets. These corrections will increase the number of emission allowances available under the CSAPR. In addition, the proposal defers until 2014 penalties that will involve surrender of additional allowances should states not meet certain levels of emission reductions. This deferral is intended to increase the liquidity of allowances during the initial years of transition from CAIR to CSAPR. Upon preliminary review, it is expected that implementation of the CSAPR will modestly increase power prices over the long term, which would result in a net benefit to Generation's results of operations and cash flows.

Several entities challenged the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit, and 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 and directed the U.S. EPA to continue the administration of CAIR in the interim. The Court ordered an expedited briefing schedule that requires that final briefs be submitted by March 16, 2012, and scheduled oral argument for April 13, 2012. It is unknown when the Court will issue its decision on the merits. Exelon believes that CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the CAA. Exelon has received permission from the Court to intervene in support of CSAPR and in opposition to the stay.

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 new source performance standards for electric generating units. The final rule, known as the Mercury and Air Toxics (MATS) rule, 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. 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. 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 cumulative impact of these 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.

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 PSD and Title V operating permit sections of the Clean Air Act for new and modified stationary sources that became effective on January 2, 2011.

Exelon supports comprehensive climate change legislation by the U.S Congress, including a mandatory, economy−wide cap−and−trade program for GHG emissions that balances the need to protect consumers, business and the economy with the urgent need to reduce national GHG emissions. Several bills containing provisions for legislation of GHG emissions were introduced in Congress from January 2009 through January 2011, but none were passed by both houses of Congress.

Water. 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. Regulations adopted by the U.S. EPA in 2004 applicable to large electric generating stations were withdrawn in 2007 following a decision by the U.S. Second Circuit Court of Appeals that invalidated many of the rule's significant provisions and remanded the rule to the EPA for further consideration and revision. On March 28, 2011, the EPA issued a proposed rule, and is required under a Settlement Agreement to issue a final rule by July 27, 2012. 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 or permit will require closed−cycle cooling at Salem. In addition, the economic viability of Generation's other power generation 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.

Waste. Under proposed U.S. EPA rules issued on June 21, 2010, coal combustion waste (CCW) would be regulated for the first time under the RCRA. The U.S. EPA is considering several options, including classification of CCW either as a hazardous or non−hazardous waste. Under either option, the U.S. EPA's intention is the ultimate elimination of surface impoundments as a waste treatment process. For plants affected by the proposed rules, this would result in significant capital expenditures and variable operating and maintenance expenditures to convert to dry handling and disposal systems and installation of new waste water treatment facilities. Generation anticipates that the only plants in which it has an ownership interest that would be affected by proposed rules would be Keystone and Conemaugh. As a result, Exelon does not currently expect the adoption of the rules as proposed to have a significant impact on its future capital spending requirements and operating costs. The U.S. EPA has not announced a target date for finalization of the CCW rules.

See Note 18 of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters, including the impact of environmental regulation.

Regulatory and Legislative Matters

Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process. On October 26, 2011, the Illinois General Assembly overrode the Governor's veto of the Illinois Energy Infrastructure Modernization Act (SB 1652), which became effective immediately. The Illinois General Assembly also passed House Bill 3036 (the Trailer Bill), which modifies and supplements SB 1652. The Governor signed the Trailer Bill into law on December 30, 2011. The combined legislation (EIMA) provides for substantial capital investment over a ten−year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre−established formula rate tariff. 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. In addition, ComEd will make contributions to fund customer assistance programs and for a new Science and Technology Innovation Trust fund as a result of the combined legislation. The legislation also contains a provision for the IPA to complete a procurement event for energy and REC requirements for the June 2013 through May 2017 period In order to protect consumers, EIMA contains several restrictions and potential criteria for the program to terminate prematurely, ending ComEd's investment commitment and the performance−based distribution formula rates.

On November 8, 2011, ComEd filed its initial formula rate tariff and associated testimony based on 2010 costs and 2011 plant additions. The ICC will review ComEd's rate filing to evaluate the prudence and reasonableness of the costs and issue its order in a shortened proceeding. This rate will take effect within 30 days after the ICC order, which must be issued by May 31, 2012.

The legislation provides for an annual reconciliation of the revenue requirement in effect to reflect the actual costs incurred in a given year. ComEd will make its initial reconciliation filing in May 2012, and the rate adjustments necessary to reconcile 2011 revenues to ComEd's actual 2011 costs incurred will take effect in January 2013 after the ICC's review. As of December 31, 2011, ComEd recorded an estimated regulatory asset of approximately $84 million and an offsetting increase in revenues for the 2011 reconciliation and net decrease in operating and maintenance expense for the deferral of certain storm costs of $29 million and $55 million, respectively. This regulatory asset represents ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide ComEd recovery of all prudently and reasonably incurred costs in 2011 and an earned rate of return on common equity, as defined in the legislation, for 2011. As the ICC proceeding to review ComEd's initially filed formula rate tariff progresses through May 2012, ComEd will adjust the estimated regulatory asset recorded as of December 31, 2011, to reflect any revisions made to the proposed formula by the ICC. ComEd currently does not anticipate any such adjustments would be material to its overall results of operations, financial position or cash flows. The positive impact of the reconciliation mechanism on ComEd's 2011 pre−tax income was partially offset by the recognition of $15 million contribution to be made to the Science and Technology Innovation Trust fund discussed above. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Appeal of 2007 Illinois Electric Distribution Rate Case. On September 30, 2010, the Illinois Appellate Court (Court) issued a decision in the appeals related to the ICC's order in ComEd's 2007 electric distribution rate case (2007 Rate Case). That decision ruled against ComEd on the treatment of post−test year accumulated depreciation and the recovery of costs for an AMI/Customer Applications pilot program via a rider (Rider SMP). On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court that was denied on March 30 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in early 2012. ComEd filed testimony that no refunds should be required in this proceeding and in the event of any refund, the maximum refund should be $30 million. On November 10, 2011, the ALJ issued a proposed order in the remand proceeding agreeing with ComEd that the ICC does not have the legal authority to order a refund; a refund may only be ordered by a court. The ALJ also concluded that, to the extent that a court orders a refund, it should be in the amount of $37 million, including interest. As of December 31, 2011, ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to reconciliation when the ICC issues a final order. ComEd does not believe any of its other riders are affected by the Court's ruling. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to the Court's order.

2010 Illinois Electric Distribution Rate Case. On May 24, 2011, the ICC issued an order in ComEd's 2010 electric delivery services rate case. ComEd requested an increase in the annual revenue requirement to allow ComEd to recover the costs of substantial investments made in its distribution system since its last rate filing in 2007. The requested increase also reflected increased costs, most notably pension and other postretirement employee benefits, since ComEd's rates were last determined.

The ICC order, which became effective on June 1, 2011, approved a $143 million increase to ComEd's annual delivery services revenue requirement, which is approximately 42% of the $343 million requested by ComEd in its reply brief on February 23, 2011. The approved rate of return on common equity is 10.50%. As a result of the order, ComEd recorded a one−time net benefit of approximately $58 million that includes the reestablishment of previously expensed plant balances, the establishment of new regulatory assets, and the reversal of certain reserves. The benefit is reflected as an increase to operating revenues and a reduction in operating and maintenance expense and income tax expense for the nine months ended September 30, 2011. The order has been appealed to the Court by several parties. ComEd cannot predict the results of these appeals. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to the 2010 Rate Case.

PECO's Default Service Provider Programs. Beginning in January 2011, PECO procured electric supply for default electric service customers through contracts executed through competitive procurements conducted in accordance with its DSP Program approved by the PAPUC in 2009. PECO will conduct three additional competitive procurements under the term of this DSP Program, which expires May 31, 2013.

On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC, which outlined how PECO will purchase electric supply for default service customers from June 1, 2013 through May 31, 2015. The plan proposed to procure electric supply through a combination of one−year and two−year fixed full requirements contracts, reduce the amount of time between when the energy is purchased and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. The plan also proposed 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. Hearings on the filing will be held in the summer of 2012 with a PAPUC ruling expected in mid−October 2012.

See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to PECO's rate case settlements and procurement proceedings.

Smart Meter and Smart Grid Investments. In April 2010, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan under which PECO will deploy 600,000 smart meters within three years and deploy smart meters to all of its electric customers by 2020. Also in April 2010, PECO entered into a Financial Assistance Agreement with the DOE for a $200 million award for SGIG funds under the ARRA of 2009. In total, through 2020, PECO plans to spend up to a total of $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG from the DOE is being used to reduce the impact of these investments on PECO ratepayers.

Financial Reform Legislation. The Dodd−Frank Wall Street Reform and Consumer Protection Act (Dodd−Frank) was enacted into law on July 21, 2010. Its primary objective is to eliminate from the financial system the systemic risk that Congress believed was in part the cause of the financial crisis in 2008. Dodd−Frank ushers in a new regulatory framework applicable to the over−the−counter (OTC) market for swaps. Generation relies on the OTC swaps markets as part of its program to hedge the price risk associated with its generation portfolio.

Since the Fall of 2010, the SEC, Commodity Futures Trading Commission (CFTC), and the Federal Reserve have issued hundreds of proposed rules designed to carry out the mandates contained in Dodd−Frank. With respect to non−banks such as Exelon, the primary regulator will be the CFTC. Although a few of the rules that will affect Exelon have become final, most will not until, at the earliest, the middle of 2012.

The starting point that will determine the ultimate impact on Generation is the definition of "swap dealer," as the regulation is aimed at dealers in a manner that is analogous to the CFTC's long−standing jurisdiction over the exchanges, such as the NYMEX, which are the clearinghouses for exchange−traded futures and options. The CFTC has not yet issued its final rule defining swap dealer. Although the regulation applicable to swap dealers will be far more extensive, end−users will also face new requirements that could have a material impact on Generation.

Swap dealers will be subject to significant reporting requirements, both in the normal course to the CFTC or its designee swap data repository (SDR), and in real−time to the CFTC or an SDR as they enter into transactions. Swap dealers will also be required to demand margin from other swap dealers and also entities that are major swap participants (MSPs) that could be above amounts parties' currently request based on current industry norms regarding credit quality. Swap dealers will also have to clear all transactions through CFTC−approved exchanges and clearinghouses, except for transactions that they enter into with end−users that elect to rely on the exception to the clearing requirement available only to end−users whose transactions are hedges of their commercial risk. Swap dealers will have to abide by specific business conduct standards, some of which are similar to fiduciary obligations that entities in other businesses owe to their customers under other laws. Swap dealers will be subject to position limits in a broad range of commodities. Finally, swap dealers will be subject to capitalization requirements that in some cases cannot be met through guarantees from their parent companies.

End−users will also have reporting obligations, but only with respect to some transactions done with other end−users. The clearing requirement will also be applicable to them, except that they will have the option not to clear a transaction that is a qualifying hedge of their commercial risk if they can demonstrate to the CFTC that it is capable of generally meeting its financial obligations associated with uncleared swaps. In addition, end−users will be subject to the same position limits as are applicable to swap dealers.

Although Exelon and Generation believe a swap dealer designation is unlikely for Generation. Generation estimates that a substantial shift from over−the−counter sales to exchange cleared sales would to require up to $1 billion of additional collateral postings by Generation based upon market conditions as of December 31, 2011. The level of collateral required would rely upon multiple factors, including but not limited to market conditions, derivative activity levels and Generation's credit ratings. Generation has adequate credit facilities and flexibility in its hedging program to accommodate these legislative or market changes. 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.

New Jersey Capacity Legislation. New Jersey Senate Bill 2381 was enacted into law on January 28, 2011. This legislation established a long−term capacity pilot program under which the New Jersey Board of Public Utilities (NJBPU) administered an RFP process in the first quarter of 2011 to solicit offers for capacity agreements with mid−merit and/or base−load generation constructed after the effective date of the bill. In the first quarter of 2011, the NJBPU approved the RFP results, which included capacity agreements for a term of up to 15 years for 2,000 MWs. Generation and others filed a complaint in Federal district court requesting that the court declare the statute unconstitutional and that it enjoin implementation of the statute, and have filed a motion for summary judgment in that proceeding asking the court to find the state's actions preempted by the Federal Power Act. On December 14, 2011, the NJBPU Staff issued its report on New Jersey Capacity, Transmission Planning and Interconnection Issues. The Report makes several recommendations for NJBPU involvement in ongoing and anticipated PJM activities to revise interconnection and transmission planning processes and recommends continued actions to appeal PJM's MOPR.

The selected generators from the RFP process are required to bid in and clear the PJM RPM auction, likely causing them to bid in the PJM RPM auction at zero. Under the pilot program, generators are paid based on the RFP contract price; therefore, any difference between the RPM clearing price and the RFP contract price is either ultimately recovered from or refunded to New Jersey electric customers. This state−required customer subsidy for generation capacity is expected to artificially suppress capacity prices within the Mid−Atlantic region in future auctions, which could adversely affect Generation's results of operations and cash flows. Other states could seek to establish similar programs, which could substantially impair Exelon's market driven position.

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. See Note 2 of the Combined Notes to Consolidated Financial Statements for further details related to PJM's MOPR.

Tax Matters

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. For the year ended December 31, 2011, the adoption of the safe harbor resulted in a $35 million reduction of 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. For Exelon, the adoption had a minimal effect on consolidated earnings. In addition, the adoption of the safe harbor will result in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million. See Notes 2 and 11 of the Combined Notes to Consolidated Financial Statements for additional information on the electric transmission and distribution property repairs.

Nuclear Decommissioning Trust Fund Special Transfer Tax Deduction. During 2008, Generation benefited from a provision in the Energy Policy Act of 2005 which allowed companies an income tax deduction for a "special transfer" of funds from a non−tax qualified NDT fund to a qualified NDT fund. As a result of temporary guidance published by the U.S. Department of Treasury, Generation completed a special transfer in the first quarter of 2008 for tax year 2008. In December 2010, the U.S. Department of Treasury issued final regulations under IRC Section 468A. The final regulations included a transitional relief provision that allowed taxpayers to request permission from the IRS to designate a taxable year, as far back as 2006, during which the special transfer will be deemed to have occurred. Exelon determined, and confirmed with the IRS through the ruling process, that this provision allows a majority of Generation's 2008 special transfer deduction to be claimed in the 2006 tax year and the remaining portions claimed ratably in taxable years 2007 and 2008. On February 18, 2011, in order to preserve both the ability to designate the special transfer from 2008 to an earlier taxable year and the ability to complete future additional special transfers, Exelon filed ruling requests with the IRS. During 2011, Exelon received favorable rulings from the IRS on all of its ruling requests. As a result, Exelon recorded an interest and tax benefit of $46 million, net of tax including the impact on the manufacturer's deduction, in 2011 related to the special transfers completed in 2008 and 2011.

Illinois State Income Tax 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 recorded 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 discussed in Note 11 of the Combined Notes to Consolidated Financial Statements.

Plant Retirements

Oyster Creek. On December 9, 2010, Generation agreed to permanently cease generation operations at Oyster Creek no later than December 31, 2019, in view of the costs that might have been associated with the installation of closed−cycle cooling had operations continued to the end of its current NRC license in 2029.

Eddystone and Cromby. 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; on December 31, 2011, Cromby Unit 2 was retired and Eddystone Unit 2 will retire 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. In addition, Generation is recovering 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 began operating under the reliability−must−run agreement effective June 1, 2011.

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 (Exelon and Generation)

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 $3.7 billion at December 31, 2011.

The authoritative guidance requires that Generation estimate its obligation for the future decommissioning of its nuclear generating plants. To estimate that liability, Generation uses a probability−weighted, discounted cash flow model that considers multiple outcome scenarios based upon significant estimates and assumptions embedded in the following:

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 Studies. 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 assigned alternative decommissioning approaches 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 currently assumes will begin in 2020, based on the DOE's most recent indication. For more information regarding the estimated date that DOE will begin accepting SNF, see Note 18 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 18 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 has 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 $170 million per unit as of December 31, 2011. 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. Changes in the CARFR could result in significant changes in the ARO. If Generation used a 2010 CARFR instead of the 2011 CARFR in performing its third quarter 2011 ARO update, it would have resulted in a $140 million increase in the ARO. Additionally, if the CARFR used in performing the third quarter 2011 ARO update was increased or decreased by 25 basis points, the ARO would have decreased by $50 million or increased by $20 million, respectively.

Table of Contents

Changes in the assumptions underlying the foregoing items could materially affect the decommissioning obligation. 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, 2011
Cost escalation studies		
Uniform increase in escalation rates of 25 basis points	$	410
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	$	120
Increase the likelihood of the DECON scenario by 10 percentage points and decrease the likelihood of the SAFSTOR scenario by 10 percentage points	$	180
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	$	340
Extend the estimated date for DOE acceptance of SNF to 2025	$	150
Extend the estimated date for DOE acceptance of SNF to 2035	$	250

Under the authoritative guidance, 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. For more information regarding accounting for nuclear decommissioning obligations, see Notes 1 and 12 of the Combined Notes to Consolidated Financial Statements.

Goodwill (Exelon and ComEd)

ComEd has goodwill 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 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. The impairment assessment is performed using a two−step, fair value based test. 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, operating and capital expenditure requirements and the fair value of debt. In applying the second step (if needed), management would need to estimate the fair value of specific assets and liabilities of the reporting unit.

ComEd did not recognize an impairment in 2011; however, a fully successful IRS challenge to Exelon’s and ComEd’s like−kind exchange income tax position or adverse regulatory actions such as early termination of EIMA in combination with changes in significant assumptions described above could potentially result in a future impairment loss of ComEd’s goodwill, which could be material. If any combination of changes to significant assumptions resulted in a 5% reduction in the fair value of the reporting unit as of November 1, 2011, ComEd still would have passed the first step of the goodwill assessment. See Notes 2 and 7 of the Combined Notes to Consolidated Financial Statements for additional information.

Purchase Accounting (Exelon and Generation)

In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the balance sheet if it exceeds the estimated fair value and as a bargain purchase gain on the income statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed in a business combination is judgmental in nature and often involves the use of significant estimates and assumptions. Some of the more significant estimates and assumptions used in valuing Generation’s acquisitions of Antelope Valley Solar Ranch One on September 28, 2011, Wolf Hollow, LLC on August 24, 2011 and Exelon Wind on December 10, 2010 include: projected future cash flows (including timing) which are estimated primarily utilizing the income approach; discount rates reflecting the risk inherent in the future cash flows; and future market prices. The determination of fair value is driven by both internal assumptions as well as information from various public, financial and industry sources. There are also judgments made to determine the expected useful lives assigned to each class of assets acquired and the duration of the liabilities assumed. 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 3 of the Combined Notes to Consolidated Financial Statements for additional information.

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

Exelon, Generation, ComEd and PECO evaluate their long−lived assets, 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 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. The review of long−lived assets 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 realizability of an asset 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 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. For ComEd and PECO, 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, 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. 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. Additionally, some assumptions or projections inevitably will not materialize and unanticipated events and circumstances may occur during the forecast period. These could include, among others, major changes in the economic environment; significant increases or decreases in current mortgage interest rates and/or terms or availability of financing altogether; property assessment; and/or major revisions in current state and/or Federal tax or regulatory laws. Therefore, the actual results achieved during the projected holding period and investor requirements relative to anticipated annual returns and overall yields could vary from the projection. 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 both the long−lived asset and current period earnings by the amount of the impairment.

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.

See Note 5 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 (Exelon, Generation, ComEd and PECO)

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. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding 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 periodically evaluates 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 the hydroelectric generating facilities are based on the remaining useful lives of the stations, which assume a license renewal extension of the 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.

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, 2011.

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

Exelon sponsors defined benefit pension plans and other postretirement benefit plans for substantially all Generation, ComEd, PECO and BSC employees. See Note 13 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 other factors. The assumptions are updated annually and upon any interim remeasurement of the plan obligations. The impact of assumption changes on pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the employees rather than immediately recognized in the income statement. 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 13 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 8.00%, 8.50% and 8.50% for 2011, 2010 and 2009, respectively. The weighted average expected return on assets assumption used in calculating other postretirement benefit costs was 7.08%, 7.83% and 8.10% in 2011, 2010 and 2009, 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 13 of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's asset allocations. Exelon used an EROA of 7.50% and 6.68% to estimate its 2012 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, 2011 were 9.8% and 2.0%, respectively, compared to an expected long−term return assumption of 8.00% and 7.08%, respectively.

Discount Rate. The discount rates used to determine the pension and other postretirement benefit obligations at December 31, 2011 were 4.74% and 4.80%, respectively, and the discount rates for determining the pension and other postretirement benefit obligations at December 31, 2010 were 5.26% and 5.30%, respectively. At December 31, 2011 and 2010, the discount rates were determined by developing a spot rate curve based on the yield to maturity of a universe of high−quality non−callable (or callable with make whole provisions) bonds with similar maturities to the related pension and other postretirement benefit obligations. The spot rates are used to discount the estimated distributions under the pension and other postretirement benefit plans. The discount rate is the single level rate that produces the same result as the spot rate curve. Exelon utilizes an analytical tool developed by its actuaries to determine the discount rates.

The discount rate assumptions used to determine the obligation at year end are used to determine the cost for the following year. Exelon will use discount rates of 4.74% and 4.80% to estimate its 2012 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 intends to make a change in the manner in which it receives prescription drug subsidies 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

Table of Contents
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 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.

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, 2011, 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 2011 cost:				
Discount rate (a)	0.5%	$ (54)	$ (23)	$ (77)
	(0.5%)	54	30	84
EROA	0.5%	(59)	(8)	(67)
	(0.5%)	59	8	67
Health care cost trend rate	1.00%	N/A	75	75
	(1.00%)	N/A	(57)	(57)
	Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached from 2015 to 2017	N/A	6	6
Change in benefit obligation at December 31, 2011:				
Discount rate (a)	0.5%	(819)	(252)	(1,071)
	(0.5%)	873	269	1,142
Health care cost trend rate	1.00%	N/A	686	686
	(1.00%)	N/A	(521)	(521)
	Extend the year at which the ultimate health care trend rate of 5% is forecasted to be reached from 2015 to 2017	N/A	61	61

(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 12.1 years, 12.4 years and 12.7 years for the years ended December 31, 2011, 2010 and 2009, respectively.

For other postretirement benefits, Exelon amortizes its unrecognized estimated 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 6.6 years, 6.8 years and 6.8 years for the years ended December 31, 2011, 2010 and 2009, respectively. The average remaining service period of postretirement benefit plan participants related to expected retirement was 8.7 years, 9.0 years and 9.2 years for the years ended December 31, 2011, 2010 and 2009, respectively.

Regulatory Accounting (Exelon, ComEd and PECO)

Exelon, ComEd and PECO 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, and PECO 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, 2011, Exelon, ComEd and PECO have concluded that the operations of ComEd and PECO 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 and PECO 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 2 of the Combined Notes to Consolidated Financial Statements for additional information regarding regulatory matters, including the regulatory assets and liabilities tables of Exelon, ComEd and PECO.

For each regulatory jurisdiction in which they conduct business, Exelon, ComEd and PECO 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 factors such as changes in applicable regulatory and political environments, historical regulatory treatment for similar costs in ComEd's and PECO's jurisdictions, and recent rate orders. Furthermore, Exelon, ComEd and PECO 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 and the types of costs and the extent, if any, to which those 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 tariff. 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 and PECO'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 and PECO are ultimately different than actual regulatory outcomes, the impact on their results of operations, financial position, and cash flows could be material.

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

The Registrants utilize derivative instruments to manage their exposure to fluctuations in interest rates, changes in interest rates related to planned future debt issuances and changes in the fair value of outstanding debt. Generation uses a variety of derivative and non−derivative instruments to manage the commodity price risk of its electric generation facilities, including power sales, fuel and energy purchases and other energy−related products marketed and purchased. Additionally, Generation enters into energy−related derivatives for proprietary trading purposes. ComEd has entered into contracts to procure energy, capacity and ancillary services. In addition, ComEd 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. ComEd and PECO 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 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

The Registrants account for derivative financial instruments under the applicable authoritative guidance. Determining whether or not a contract qualifies as a derivative under this guidance requires that management exercise significant judgment, including assessing the market liquidity as well as determining whether a contract has one or more underlyings and one or more notional amounts. Further, interpretive guidance related to the authoritative literature continues to evolve, including how it applies to energy and energy−related products. Changes in management's assessment of contracts and the liquidity of their markets, and changes in authoritative guidance related to derivatives, could result in previously excluded contracts being subject to the provisions of the authoritative derivative guidance. Generation has determined that contracts to purchase uranium and contracts to purchase and sell 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 nor the REC markets are sufficiently liquid to conclude that forward contracts are readily convertible to cash. If the uranium or REC markets do become sufficiently liquid in the future and Generation begins to account for uranium purchase contracts or REC sale and purchase 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 a mark−to−market gain or loss, which may have a material 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 unless they qualify for a 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 other derivative contracts that do not qualify or 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 and PECO, 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 price is not tied to an unrelated underlying derivative. 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 these contracts are considered derivative financial instruments under the authoritative guidance, the 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 and most of PECO's 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 and PECO. 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 (book−outs).

Commodity Contracts. Identification of a commodity contract as a qualifying cash flow hedge requires Generation to determine that the contract is in accordance with the RMP, the forecasted future transaction is probable and the hedging relationship between the commodity contract and the expected future purchase or sale of the commodity is expected to be highly effective at the initiation of the hedge and throughout the hedging relationship. Internal models that measure the statistical correlation between the derivative and the associated hedged item determine the effectiveness of such a commodity contract designated as a hedge. Generation reassesses its cash flow hedges on a regular basis to determine if they continue to be effective and whether the forecasted future transactions remain probable. When a contract does not meet the effective or probable criteria of the authoritative guidance, hedge accounting is discontinued and changes in the fair value of the derivative are recorded through earnings at Generation or offset by a regulatory asset or liability at ComEd and PECO.

As a part of accounting for derivatives, the Registrants make estimates and assumptions concerning future commodity prices, load requirements, interest rates, the timing of future transactions and their probable cash flows, the fair value of contracts and the expected changes in the fair value in deciding whether or not to enter into derivative transactions, and in determining the initial accounting treatment for derivative transactions. In accordance with the authoritative guidance for fair value measurements, the Registrants categorize these derivatives under a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. Derivative contracts are traded in both exchange−based and non−exchange−based markets. Exchange−based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain 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 the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid−ask spreads and contract duration. The Registrant's 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, Black 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, Black 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 Black model inputs generally are not observable. The Registrants consider nonperformance risk, including credit risk in the valuation of derivative contracts categorized in Level 1, 2 and 3, including both historical and current market data in its assessment of nonperformance risk, including credit risk. The impacts of credit and nonperformance risk to date have generally not been material to the financial statements.

Interest Rate Derivative Instruments. The Registrants may utilize fixed−to−floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable−rate debt as a percent of total debt. Additionally, the Registrants may use forward−starting interest rate swaps and treasury rate locks to lock in interest−rate levels in anticipation of future financings. The fair value of the swap 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 ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK and Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding the Registrants' derivative instruments.

Taxation (Exelon, Generation, ComEd and PECO)

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

The Registrants evaluate quarterly the probability of realizing deferred tax assets by reviewing a forecast of future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. The Registrants also assess their ability to utilize tax attributes, including those in the form of carryforwards, for which the benefits have already been reflected in the financial statements. The Registrants record valuation allowances for deferred tax assets when the Registrants conclude it is more likely than not such benefit will not be realized in future periods.

Actual income taxes could vary from estimated amounts due to the future impacts of various items, including changes in income tax laws, the Registrants' forecasted financial condition and results of operations, failure to successfully implement tax planning strategies, as well as results of audits and examinations of filed tax returns by taxing authorities. While the Registrants believe the resulting tax balances as of December 31, 2011 and 2010 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 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding taxes.

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

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

Environmental Costs. Environmental investigation and remediation liabilities are based upon estimates with respect to the number of sites for which the Registrants will be responsible, the scope and cost of work to be performed at each site, the portion of costs that will be shared with other parties, the timing of the remediation work, changes in technology, regulations and the requirements of local governmental authorities. Annual studies are conducted to determine the future remediation requirements and estimates are adjusted accordingly. These matters, if resolved in a manner different from the estimate, could have a material effect on the Registrants' results of operations, financial position and cash flows. See Note 18 of the Combined Notes to Consolidated Financial Statements for further information.

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

Revenue Recognition (Exelon, Generation, ComEd and PECO)

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 and PECO'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. 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, and ComEd's FERC−approved transmission formula rate tariff provide for annual reconciliations to the distribution and transmission revenue requirements, respectively. As of the balance sheet dates, ComEd has recorded 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 the formula rate mechanisms. 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. Both estimated reconciliations can be impacted by, among other things, variances in costs incurred and investments made and actions by regulators or courts. The structure of ComEd's distribution formula rate tariff could change once the ICC proceeding to review ComEd's initially filed formula rate tariff is completed in May 2012. ComEd does not anticipate that any of the adjustments to the reconciliations discussed above would be material to ComEd's overall results of operations, financial position or cash flows.

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 (Exelon, Generation, ComEd and PECO)

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying internally developed loss rates 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. ComEd and PECO 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 and PECO customer accounts are written off consistent with approved regulatory requirements. ComEd's and PECO's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC and PAPUC regulations, respectively. See Note 4 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, 2011, 2010 and 2009 set forth below include intercompany transactions, which are eliminated in Exelon's consolidated financial statements.

Table of Contents

Net Income (Loss) by Business Segment

	2011	2010	Favorable (unfavorable) 2011 vs. 2010 variance	2009	Favorable (unfavorable) 2010 vs. 2009 variance
Generation	$1,771	$1,972	$ (201)	$2,122	$ (150)
ComEd	416	337	79	374	(37)
PECO	389	324	65	353	(29)
Other (a)	(81)	(70)	(11)	(142)	72
Total	$2,495	$2,563	$ (68)	$2,707	$ (144)

(a) Other primarily includes corporate operations, BSC and intersegment eliminations.

Results of Operations—Generation

	2011	2010	Favorable (unfavorable) 2011 vs. 2010 variance	2009	Favorable (unfavorable) 2010 vs. 2009 variance
Operating revenues	$10,308	$10,025	$ 283	$9,703	$ 322
Purchased power and fuel expense	3,450	3,463	13	2,932	(531)
Revenue net of purchased power and fuel expense (a)	6,858	6,562	296	6,771	(209)
Other operating expenses					
Operating and maintenance	3,148	2,812	(336)	2,938	126
Depreciation and amortization	570	474	(96)	333	(141)
Taxes other than income	264	230	(34)	205	(25)
Total other operating expenses	3,982	3,516	(466)	3,476	(40)
Operating income	2,876	3,046	(170)	3,295	(249)
Other income and deductions					
Interest expense	(170)	(153)	(17)	(113)	(40)
Loss in equity method investments	(1)	—	(1)	(3)	3
Other, net	122	257	(135)	376	(119)
Total other income and deductions	(49)	104	(153)	260	(156)
Income before income taxes	2,827	3,150	(323)	3,555	(405)
Income taxes	1,056	1,178	122	1,433	255
Net income	$ 1,771	$ 1,972	$ (201)	$2,122	$ (150)

(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.

Net Income

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

Table of Contents
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 South and West region.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Generation's 2010 results compared to 2009 were lower due to decreased revenue net of purchased power and fuel expense due to lower margins realized on market and affiliate power sales primarily due to unfavorable market conditions, lower mark−to−market gains on economic hedging activities and increased nuclear fuel costs; partially offset by higher capacity revenues, including RPM, and favorable settlements on the ComEd swap.

Generation's 2010 results compared to 2009 were further affected by lower operating and maintenance expenses. Lower operating and maintenance expenses were primarily due to the impact of a $223 million charge associated with the impairment of the Handley and Mountain Creek stations recorded in 2009. Lower operating and maintenance expenses were partially offset by higher expense due to the absence of ARO reductions that occurred in 2009; higher wages and benefits costs; and higher nuclear refueling outage costs in 2010. Additionally, Generation's earnings decreased due to lower unrealized gains in its NDTs of the Non−Regulatory Agreement Units in 2010 compared to 2009.

Revenue Net of Purchased Power and Fuel Expense

Generation has three reportable segments, the Mid−Atlantic, Midwest, and South and West regions representing the different geographical areas in which Generation's power marketing activities are conducted. Mid−Atlantic includes Generation's operations primarily in Pennsylvania, New Jersey and Maryland; Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota; and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon.

Generation evaluates the operating performance of its power marketing activities using the measure of revenue net of purchased power and fuel expense. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd and PECO. 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. Generation's retail gas, proprietary trading, compensation under the reliability−must−run rate schedule, other revenues and mark−to−market activities as well as amounts paid related to the Illinois Settlement Legislation are not allocated to a region.

For the year ended December 31, 2011 compared to 2010 and 2010 compared to 2009, Generation's revenue net of purchased power and fuel expense by region were as follows:

			2011 vs. 2010			2010 vs. 2009	
	2011	2010	Variance	% Change	2009	Variance	% Change
Mid−Atlantic [a][b]	$3,359	$2,512	$ 847	33.7%	$2,578	$ (66)	(2.6)%
Midwest [b]	3,547	4,081	(534)	(13.1)%	4,148	(67)	(1.6)%
South and West	70	(131)	201	153.4%	(117)	(14)	(12.0)%
Total electric revenue net of purchased power and fuel expense	$6,976	$6,462	$ 514	8.0%	$6,609	$ (147)	(2.2)%
Trading portfolio	24	27	(3)	(11.1)%	1	26	n.m.
Mark−to−market gains (losses)	(288)	86	(374)	n.m.	181	(95)	(52.5)%
Other [c][d]	146	(13)	159	n.m.	(20)	7	35.0%
Total revenue net of purchased power and fuel expense	$6,858	$6,562	$ 296	4.5%	$6,771	$ (209)	(3.1)%

(a) Included in the Mid−Atlantic are the results of generation in New England.
(b) Results of transactions with PECO and ComEd are included in the Mid−Atlantic and Midwest regions, respectively.
(c) Includes retail gas activities and other operating revenues, which primarily include fuel sales and compensation under the reliability−must−run rate schedule.
(d) In 2010, Other also includes a $57 million impairment charge for certain emission allowances further described in Note 18 of the Combined Notes to Consolidated Financial Statements.

Generation's supply sources by region are summarized below:

Supply source (GWh)	2011	2010	2011 vs. 2010 Variance	2011 vs. 2010 % Change	2009	2010 vs. 2009 Variance	2010 vs. 2009 % Change
Nuclear generation [(a)]							
Mid−Atlantic	47,287	47,517	(230)	(0.5)%	47,866	(349)	(0.7)%
Midwest	92,010	92,493	(483)	(0.5)%	91,804	689	0.8%
Fossil and renewables [(a)(b)]							
Mid−Atlantic [(c)]	7,580	9,436	(1,856)	(19.7)%	8,938	498	5.6%
Midwest [(c)]	596	68	528	n.m.	4	64	n.m.
South and West	3,462	1,213	2,249	185.4%	1,247	(34)	(2.7)%
Purchased power [(d)]							
Mid−Atlantic	2,898	1,918	980	51.1%	1,747	171	9.8%
Midwest	5,970	7,032	(1,062)	(15.1)%	7,738	(706)	(9.1)%
South and West	10,040	12,112	(2,072)	(17.1)%	13,721	(1,609)	(11.7)%
Total supply by region							
Mid−Atlantic	57,765	58,871	(1,106)	(1.9)%	58,551	320	0.5%
Midwest	98,576	99,593	(1,017)	(1.0)%	99,546	47	0.0%
South and West	13,502	13,325	177	1.3%	14,968	(1,643)	(11.0)%
Total supply	169,843	171,789	(1,946)	(1.1)%	173,065	(1,276)	(0.7)%

(a) Includes Generation's proportionate share of the output of its jointly owned generating plants.
(b) Includes generation in New England and excludes revenue under the reliability−must−run rate schedule.
(c) Includes generation from Exelon Wind, acquired in December 2010, of 570 GWh and 41 GWh in the Midwest and 1,432 GWh and 84 GWh in the South and West for the years ended December 31, 2011 and 2010, respectively.
(d) Includes non−PPA purchases of 3,815 GWh, 4,681 GWh and 3,535 GWh for the years ended December 31, 2011, 2010 and 2009, respectively.

Generation's sales are summarized below:

Sales (GWh) [(a)]	2011	2010	2011 vs. 2010 Variance	2011 vs. 2010 % Change	2009	2010 vs. 2009 Variance	2010 vs. 2009 % Change
ComEd [(b)]	—	5,323	(5,323)	(100.0)%	16,830	(11,507)	(68.4)%
PECO [(c)]	—	42,003	(42,003)	(100.0)%	39,897	2,106	5.3%
Market and retail [(d)]	169,843	124,463	45,380	36.5%	116,338	8,125	7.0%
Total electric sales	169,843	171,789	(1,946)	(1.1)%	173,065	(1,276)	(0.7)%

(a) Excludes physical trading volumes of 5,742 GWh, 3,625 GWh and 7,578 GWh for the years ended December 31, 2011, 2010 and 2009, respectively.
(b) Represents sales under the 2006 ComEd auction.
(c) Represents sales under the full requirements PPA, which expired on December 31, 2010.
(d) Includes sales under the ComEd RFP, settlements under the ComEd swap and sales to PECO through the competitive procurement process.

Table of Contents

The following table presents electric revenue net of purchased power and fuel expense per MWh of electricity sold during the year ended December 31, 2011 as compared to the same period in 2010 and 2010 as compared to the same period in 2009.

$/MWh	2011	2010	2011 vs. 2010 % Change	2009	2010 vs. 2009 % Change
Mid−Atlantic (a)(b)	$58.15	$42.67	36.3%	$44.03	(3.1)%
Midwest (a)(c)	$35.98	$40.98	(12.2)%	$41.67	(1.7)%
South and West	$ 5.18	$ (9.83)	152.7%	$ (7.82)	(25.7)%
Electric revenue net of purchased power and fuel expense per MWh (d)	$41.07	$37.62	9.2%	$38.20	(1.5)%

(a) Results of transactions with PECO and ComEd are included in the Mid−Atlantic and Midwest regions, respectively.
(b) Includes sales to PECO of $508 million (7,041 GWh), $2,091 million (42,003 GWh) and $2,016 million (39,897 GWh) for the years ended December 31, 2011, 2010 and 2009, respectively. Excludes compensation under the reliability−must−run rate schedule.
(c) Includes sales to ComEd of $179 million (4,731 GWh), $288 million (8,218 GWh) and $88 million (1,916 GWh) and settlements of the ComEd swap of $474 million, $385 million and $292 million for the years ended December 31, 2011, 2010 and 2009, respectively.
(d) 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, 2011, 2010 and 2009 and excludes the mark−to−market impact of Generation's economic hedging activities, trading portfolio and other.

Mid−Atlantic

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $847 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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The $66 million decrease in revenue net of purchased power and fuel expense in the Mid−Atlantic was primarily due to unfavorable pricing relating to Generation's PPA with PECO and increased fuel expense. Additionally, increased sales to PECO resulted in lower volumes available for market sales.

Midwest

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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The $67 million decrease in revenue net of purchased power and fuel expense in the Midwest was primarily due to decreased realized margins on Generation's market sales in 2010 for the volumes previously sold under the 2006 ComEd auction contracts and for sales of the additional nuclear volumes at realized lower prices as a result of unfavorable market conditions and increases in the price of nuclear fuel. These decreases were partially offset by increased payments to Generation under PJM's RPM auction and an increase in settlements on the ComEd swap as a result of declining market prices in 2010.

South and West

In the South and West, Generation is party to certain long−term purchase power agreements that have fixed capacity payments based on unit availability. The extent to which these fixed payments are recovered by Generation is dependent on market conditions.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The $201 million increase in revenue net of purchased power and fuel expense in the South and West was primarily driven by the performance of Generation's generating units during extreme weather events that occurred in Texas in February and August 2011, in addition to the impact of additional revenue from the acquisition of Exelon Wind in December 2010 and higher realized margins due to overall favorable market conditions.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The $14 million decrease in revenue net of purchased power and fuel expense in the South and West was primarily due to lower realized margins due to unfavorable market conditions and outage activity, partially offset by capacity revenues received on Generation's long−term sale agreements that began in 2010.

Mark−to−market Gains and Losses

Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. Mark−to−market losses on power hedging activities were $214 million in 2011, including the impact of the changes in ineffectiveness, compared to losses of $3 million in 2010. Mark−to−market losses on fuel hedging activities were $74 million in 2011 compared to gains of $89 million in 2010. In general, the mark−to−market losses incurred in 2011 represent the realization of in−the−money hedge transactions during the period. See Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for information on gains and losses associated with mark−to−market derivatives.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Mark−to−market losses on power hedging activities were $3 million in 2010, including the impact of the changes in ineffectiveness, compared to gains of $94 million in 2009. Mark−to−market gains on fuel hedging activities were $89 million in 2010 compared to gains of $87 million in 2009. See Notes 8 and 9 of the Combined Notes to Consolidated Financial Statements for information on gains and losses associated with mark−to−market derivatives.

Other

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The increase in other revenue net of purchased power and fuel expense is primarily due to the impacts of the impairment charge of certain emission 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 14 of the Combined Notes to Consolidated Financial Statements.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase in other is due to the impacts of $77 million in reduced customer credits issued to ComEd and Ameren associated with the Illinois Settlement Legislation further described in Note 2 of the Combined Notes to Consolidated Financial Statements. This increase in other revenue net of purchased power and fuel expense was partially offset by the $57 million impairment charge of certain emission allowances in 2010 further described in Note 18 of the Combined Notes to Consolidated Financial Statements and $13 million in lower fuel sales.

Table of Contents

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for 2011, as compared to 2010 and 2009, 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.

	2011	2010	2009
Nuclear fleet capacity factor [a]	93.3%	93.9%	93.6%
Nuclear fleet production cost per MWh [a]	$18.86	$17.31	$16.07

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC.

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, scheduled refueling outage days totaled 283 and 261, respectively. 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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The nuclear fleet capacity factor, which excludes Salem, increased primarily due to a lower number of outage days. For 2010 and 2009, scheduled refueling outage days totaled 261 and 263, respectively, and non−refueling outage days totaled 57 and 78, respectively. Higher nuclear fuel costs and higher plant operating and maintenance costs resulted in a higher production cost per MWh during 2010 as compared to 2009.

Operating and Maintenance Expense

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 increase [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 costs of $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 nuclear fuel at Zion. See Note 12 of the Combined Notes to Consolidated Financial Statements for further information regarding the ARO update in 2011.

(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 expenses related to EPA and competitive market matters.
(f) Reflects the increase in certain costs associated with the acquisitions of Exelon Wind, Wolf Hollow, Antelope Valley and the proposed acquisition of Constellation incurred in 2011. See Note 3 of the Combined Notes to Consolidated Financial Statements for further information.
(g) Includes additional environmental remediation costs recorded during 2011.

The changes in operating and maintenance expense for 2010 compared to 2009, consisted of the following:

	Increase (Decrease)
Impairment of certain generating assets [(a)]	$ (223)
Announced plant shutdowns [(b)]	(21)
Nuclear insurance credits [(c)]	(20)
2009 restructuring plan severance charges	(11)
Asset retirement obligation reduction [(d)]	51
Wages and other benefits	33
Pension and non−pension postretirement benefits expense	21
Nuclear refueling outage costs, including the co−owned Salem Plant	20
Exelon Wind acquisition [(e)]	11
Other	13
Decrease in operating and maintenance expense	$ (126)

(a) Reflects the impairment of certain generating assets in 2009. See Note 5 of the Combined Notes to Consolidated Financial Statements for further information.
(b) Primarily reflects severance−related and inventory write−down costs incurred in 2009 associated with the announced plant shutdowns. See Note 14 of the Combined Notes to Consolidated Financial Statements for further information.
(c) Reflects the impact of the return of property and business interruption insurance premiums in 2010. No premiums were returned for 2009.
(d) Primarily reflects the reduction in the ARO in excess of the related ARC balances for the non−regulatory agreement units during 2009.
(e) See Note 3 of the Combined Notes to Consolidated Financial Statements for further information.

Depreciation and Amortization

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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase in depreciation and amortization expense was a result of a change in the estimated useful lives of the plants associated with the 2009 announced shutdowns further described in Note 14 of the Combined Notes to Consolidated Financial Statements, which resulted in a depreciation expense increase of $48 million. Additionally, Generation completed a depreciation rate study during the first quarter of 2010, which resulted in a change in depreciation rates. The change in depreciation rates resulted in an increase of $21 million. The remaining increase was primarily due to higher plant balances due to capital additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages).

Taxes Other Than Income

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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase was primarily due to increased property taxes related to Generation's nuclear−fuel generating facilities.

Interest Expense

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 10 of the Combined Notes to Consolidated Financial Statements. The increase in long−term debt resulted in higher interest expense of approximately $27 million.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase in interest expense is primarily due to debt issuances in 2010 and 2009, further described in Note 10 of the Combined Notes to Consolidated Financial Statements. The increase in long−term debt resulted in higher interest expense of approximately $42 million.

Other, Net

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010. The decrease in other, net primarily reflects net unrealized losses related to the NDT funds of its 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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease primarily reflects lower net unrealized gains on the NDT funds of its Non−Regulatory Agreement Units. See the table below for additional information. Additionally, the decrease reflects the contractual elimination of $96 million of income tax expense associated with the NDT funds of the Regulatory Agreement Units in 2010 compared to the contractual elimination of $181 million of income tax expense in 2009. These decreases are partially offset by the impacts of $71 million of expense related to long−term debt extinguished in 2009 further described in Note 10 of the Combined Notes to Consolidated Financial Statements.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non−Regulatory Agreement Units recognized in other, net for 2011, 2010 and 2009:

	2011	2010	2009
Net unrealized gains (losses) on decommissioning trust funds	$ (4)	$104	$227
Net realized gains (losses) on sale of decommissioning trust funds	$(10)	$ 2	$ (19)

Effective Income Tax Rate.

Generation's effective income tax rates for the years ended December 31, 2011, 2010 and 2009 were 37.4%, 37.4% and 40.3%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

Table of Contents

Results of Operations—ComEd

	2011	2010	Favorable (unfavorable) 2011 vs. 2010 variance	2009	Favorable (unfavorable) 2010 vs. 2009 variance
Operating revenues	$6,056	$6,204	$ (148)	$5,774	$ 430
Purchased power expense	3,035	3,307	272	3,065	(242)
Revenue net of purchased power expense [(a)]	3,021	2,897	124	2,709	188
Other operating expenses					
Operating and maintenance	1,086	975	(111)	1,028	53
Operating and maintenance for regulatory required programs	115	94	(21)	63	(31)
Depreciation and amortization	542	516	(26)	494	(22)
Taxes other than income	296	256	(40)	281	25
Total other operating expenses	2,039	1,841	(198)	1,866	25
Operating income	982	1,056	(74)	843	213
Other income and deductions					
Interest expense, net	(345)	(386)	41	(319)	(67)
Other, net	29	24	5	79	(55)
Total other income and deductions	(316)	(362)	46	(240)	(122)
Income before income taxes	666	694	(28)	603	91
Income taxes	250	357	107	229	(128)
Net income	$ 416	$ 337	$ 79	$ 374	$ (37)

(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, 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 remeasurement of uncertain income tax positions in 2010 related to the 1999 sale of ComEd's fossil generating assets. The remeasurement 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.

Table of Contents

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in ComEd’s net income was primarily due to the remeasurement of uncertain income tax positions in 2009 and 2010 related to the 1999 sale of ComEd’s fossil generating assets. These remeasurements resulted in increased interest expense and income tax expense recorded in 2010, and increased interest income recorded in 2009. Net income was also reduced by higher incremental storm costs, higher depreciation and amortization expense reflecting higher plant balances, and the impact of Federal health care legislation signed into law in March 2010. These reductions to net income were partially offset by higher revenue net of purchased power expense primarily due to favorable weather conditions, a net reduction in operating and maintenance expense, and the accrual of estimated future refunds of the Illinois utility distribution tax for the 2008 and 2009 tax years.

The reduction in operating and maintenance expenses reflects the February 2010 approval by the ICC of ComEd’s uncollectible accounts expense rider mechanism, the reduction of ComEd’s ARO reserve in 2010, and a charge in 2009 for severance expense incurred as a cost to achieve savings under Exelon’s 2009 company−wide cost savings initiative.

Operating Revenues Net of 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 2 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 380,300 and 66,200 at December 31, 2011 and 2010, respectively, representing 10% and 2% of total retail customers, respectively. The significant increase in 2011 is primarily associated with the residential customer class. Retail deliveries purchased from competitive electric generation suppliers represented 56% and 52% of ComEd’s retail kWh sales at December 31, 2011 and 2010, respectively.

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 2 of the Combined Notes to Consolidated Financial Statements for additional information.

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. As a result of the September 30, 2010 Illinois Appellate Court (Court) decision in the 2007 Rate Case that 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 ongoing proceedings associated with the Court order, ComEd has updated its revenue subject to refund reserve. As of December 31, 2011, ComEd has recorded its best estimate of any refund obligations. See Note 2 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 will make its initial reconciliation filing in May 2012 and the adjusted rates will take effect in January 2013 after ICC review. As of December 31, 2011, ComEd recorded an estimated reconciliation of approximately $29 million. This does not include the reconciliation of significant storm costs discussed under operating and maintenance expense below. See Note 2 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 2 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 most recent annual 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. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

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.

Table of Contents

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 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.

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 summer months. The changes in heating and cooling degree days in ComEd’s service territory consisted of the following:

Heating and Cooling Degree−Days Twelve Months Ended December 31,	2011	2010	Normal	% Change From 2010	% Change From Normal
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.

The changes in ComEd’s electric revenue net of purchased power expense for 2010 compared to 2009 consisted of the following:

	Increase (Decrease)
Weather—delivery	$ 89
Uncollectible accounts recovery	59
Regulatory required programs cost recovery	31
Rate relief programs	7
2007 City of Chicago settlement	5
Volume—delivery	(3)
Revenues subject to refund (2007 Rate Case)	(17)
Other	17
Total increase	$ 188

Table of Contents

Weather—delivery

Revenues net of purchased power expense were higher in 2010 compared to 2009 due to favorable weather conditions. The changes in heating and cooling degree days in ComEd's service territory consisted of the following:

Heating and Cooling Degree−Days				% Change	
Twelve Months Ended December 31,	2010	2009	Normal	From 2009	From Normal
Heating Degree−Days	5,991	6,429	6,362	(6.8)%	(5.8)%
Cooling Degree−Days	1,181	589	855	100.5%	38.1%

Uncollectible accounts recovery

In 2009, comprehensive legislation was enacted into law in Illinois providing public utility companies with 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. Recovery began in April 2010. During 2010, ComEd recognized recovery of $59 million associated with this rider mechanism. This amount was offset by an equal amount of amortization of regulatory assets reflected in operating and maintenance expense.

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 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Rate relief programs

ComEd funded less rate relief credits to customers in 2010 compared to 2009. Credits provided to customers are recorded as a reduction to operating revenues; therefore, the reduction in credits resulted in an increase in revenues net of purchased power expense for 2010 compared to 2009. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

2007 City of Chicago Settlement

ComEd paid $3 million and $8 million in 2010 and 2009, 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 2010 resulted in a net increase in revenues net of purchased power expense for 2010 compared to 2009.

Volume—delivery

Revenues net of purchased power expense, exclusive of the effects of weather, decreased primarily as a result of lower delivery volume to residential customers in 2010 as compared to 2009.

Revenues subject to refund (2007 Rate Case)

ComEd recorded an estimated refund obligation of $17 million in 2010 as a result of the September 30, 2010 Illinois Appellate Court ruling regarding the treatment of post−test year accumulated depreciation in the 2007 Rate Case. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Other

Other revenues were higher in 2010 compared to 2009. Other revenues include revenues related to late payment charges, rental revenue, franchise fees, transmission revenues and recoveries of environmental remediation costs associated with MGP sites.

Operating and Maintenance Expense

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

		Increase (Decrease)
Uncollectible accounts expense [(a)]:		
One−time impact of 2010 ICC Order [(b)]	$	60
Provision		9
Recovery, net [(c)]		(42)
		27
Labor, other benefits, contracting and materials		72
Storm−related costs		70
Accrued contribution to Science and Technology Innovation Trust(d)		15
Corporate allocations		8
Deferral of storm costs pursuant to EIMA, net of amortization [(d)]		(55)
Discrete impacts from 2010 Rate Case order [(e)]		(32)
Other		6
Increase in operating and maintenance expense	$	111

(a) 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.
(b) As a result of the February 2010 ICC order, ComEd recorded a regulatory asset of $70 million and an offsetting reduction in operating and maintenance expense for the cumulative under−collections in the first quarter of 2010. In addition, ComEd recorded a one time contribution of $10 million associated with this legislation in the first quarter of 2010.
(c) Represents impacts on recoveries under ComEd's uncollectible accounts tariff.
(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, ComEd recorded a net reduction in operating and maintenance expense for costs related to three significant 2011 storms. In addition, ComEd recorded an accrual in 2011, pursuant to EIMA, for a contribution to a new Science and Technology Innovation Trust fund that will be used to fund energy innovation.
(e) 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.

Table of Contents

The changes in operating and maintenance expense for 2010 compared to 2009, consisted of the following:

		Increase (Decrease)
Uncollectible accounts expense [(a)]:		
Amortization [(b)]	$	59
One−time impact of 2010 ICC Order [(c)]		(60)
Provision [(d)]		(37)
(Under) over−recovered		(3)
		(41)
Storm−related costs		20
Pension and non−pension postretirement benefits expense		7
Injuries and damages		6
Rider SMP regulatory asset write off [(e)]		4
Corporate allocations		(8)
Labor, other benefits, contracting and materials		(9)
ARO adjustment		(10)
2009 restructuring plan severance charges		(19)
Other		(3)
Decrease in operating and maintenance expense	$	(53)

(a) 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.
(b) In 2010, ComEd recovered $59 million of operating revenues through its uncollectible accounts expense rider mechanism. An equal amount of amortization of regulatory assets was recorded in operating and maintenance expense. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information.
(c) As a result of the February 2010 ICC 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 one time contribution of $10 million associated with this legislation.
(d) Uncollectible accounts expense decreased in 2010 compared to 2009 as a result of ComEd’s increased collection activities.
(e) In 2010, ComEd recorded a write off to operation and maintenance expense of the regulatory asset associated with the AMI pilot program of $4 million as a result of the September 30, 2010 Illinois Appellate Court ruling. In addition, ComEd recorded $5 million of operation and maintenance for regulatory required programs, and $2 million of depreciation expense associated with the AMI pilot program. In 2010, ComEd recorded $11 million of operating revenues associated with the AMI pilot program recovered under Rider SMP. See Note 2 of the Combined Notes to Consolidated Financial Statements for additional information on the Illinois Appellate Court ruling.

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 2 of the Combined Notes to Consolidated Financial Statements for additional information.

Table of Contents

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2011 compared to 2010 and 2010 compared to 2009, consisted of the following:

	Increase 2011 vs. 2010	Increase 2010 vs. 2009
Depreciation expense associated with higher plant balances [a]	$ 20	$ 16
Other	6	6
Increase in depreciation and amortization expense	$ 26	$ 22

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

Taxes Other Than Income

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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. Taxes other than income taxes decreased, reflecting the accrual of estimated future refunds of Illinois utility distribution tax recorded in 2010 relating to prior tax years.

Interest Expense, Net

The changes in interest expense, net for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

	Increase (Decrease) 2011 vs. 2010	Increase (Decrease) 2010 vs. 2009
Interest expense related to uncertain tax positions [a]	$ (63)	$ 61
Interest expense on debt (including financing trusts) [b]	20	5
Other	2	1
(Decrease) increase in interest expense, net	$ (41)	$ 67

(a) During 2010, ComEd recorded $59 million of interest expense associated with the remeasurement of uncertain income tax positions related to the 1999 sale of Fossil Generating Assets.
(b) Interest expense on debt increased due to higher outstanding long−term debt balances year over year.

Other, Net

The changes in other, net for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

	Increase (Decrease) 2011 vs. 2010	Increase (Decrease) 2010 vs. 2009
Interest income related to uncertain tax positions [a]	$ 8	$ (59)
Other−than−temporary impairment of investments	—	7
Other	(3)	(3)
Increase (decrease) in Other, net	$ 5	$ (55)

(a) During 2009, ComEd recorded $66 million of interest benefit associated with the remeasurement of income tax positions, specifically related to the 1999 Sale of Fossil Generating Assets. The majority of the benefit was recorded to Other, net and $6 million was recorded as a reversal of interest expense. See Note 11 of the Combined Notes to Consolidated Financial Statements for more information.

Effective Income Tax Rate

ComEd's effective income tax rate for the years ended December 31, 2011, 2010, and 2009 was 37.5%, 51.4% and 38.0%, respectively. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

ComEd Electric Operating Statistics and Revenue Detail

Retail Deliveries to customers (in GWhs)	2011	2010	% Change 2011 vs. 2010	Weather–Normal % Change	2009	% Change 2010 vs. 2009	Weather–Normal % Change
Retail Delivery and Sales [(a)]							
Residential	28,273	29,171	(3.1)%	(1.3)%	26,621	9.6%	(1.2)%
Small commercial & industrial	32,281	32,904	(1.9)%	(0.8)%	32,234	2.1%	(0.6)%
Large commercial & industrial	27,732	27,717	0.1%	0.6%	26,668	3.9%	2.6%
Public authorities & electric railroads	1,235	1,273	(3.0)%	(1.2)%	1,237	2.9%	2.4%
Total Retail	89,521	91,065	(1.7)%	(0.5)%	86,760	5.0%	0.2%

Number of Electric Customers	As of December 31, 2011	2010	2009
Residential	3,448,481	3,438,677	3,425,570
Small commercial & industrial	365,824	363,393	360,779
Large commercial & industrial	2,032	2,005	1,985
Public authorities & electric railroads	4,797	5,078	5,008
Total	3,821,134	3,809,153	3,793,342

Electric Revenue	2011	2010	% Change 2011 vs. 2010	2009	% Change 2010 vs. 2009
Retail Delivery and Sales [(a)]					
Residential	$3,510	$3,549	(1.1)%	$3,115	13.9%
Small commercial & industrial	1,517	1,639	(7.4)%	1,660	(1.3)%
Large commercial & industrial	383	397	(3.5)%	387	2.6%
Public authorities & electric railroads	50	62	(19.4)%	57	8.8%
Total Retail	5,460	5,647	(3.3)%	5,219	8.2%
Other Revenue [(b)]	596	557	7.0%	555	0.4%
Total Electric Revenues	$6,056	$6,204	(2.4)%	$5,774	7.4%

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

Results of Operations—PECO

	2011	2010	Favorable (unfavorable) 2011 vs. 2010 variance	2009	Favorable (unfavorable) 2010 vs. 2009 variance
Operating revenues	$3,720	$5,519	$ (1,799)	$5,311	$ 208
Purchased power and fuel expense	1,864	2,762	898	2,746	(16)
Revenue net of purchased power and fuel expense (a)	1,856	2,757	(901)	2,565	192
Other operating expenses					
Operating and maintenance	725	680	(45)	640	(40)
Operating and maintenance for regulatory required programs	69	53	(16)	—	(53)
Depreciation and amortization	202	1,060	858	952	(108)
Taxes other than income	205	303	98	276	(27)
Total other operating expenses	1,201	2,096	895	1,868	(228)
Operating income	655	661	(6)	697	(36)
Other income and deductions					
Interest expense, net	(134)	(193)	59	(187)	(6)
Loss in equity method investments	—	—	—	(24)	24
Other, net	14	8	6	13	(5)
Total other income and deductions	(120)	(185)	65	(198)	13
Income before income taxes	535	476	59	499	(23)
Income taxes	146	152	6	146	(6)
Net income	389	324	65	353	(29)
Preferred security dividends	4	4	—	4	—
Net income on common stock	$ 385	$ 320	$ 65	$ 349	$ (29)

(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, 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. The decreased interest expense related to the retirement of PETT transition bonds on September 1, 2010 and the impact of the change in measurement of uncertain tax positions in the second quarter of 2010. The decrease in income tax expense was primarily a result of the election of the safe harbor method of tax accounting for electric distribution property. See Note 11 of the Combined Notes to the Consolidated Financial Statements for further discussion of the election of the safe harbor method.

Table of Contents

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in net income was primarily driven by increased operating expenses partially offset by increased electric revenues net of purchased power expense. The increase in operating expenses reflected higher storm costs and increased scheduled CTC amortization expense. Electric revenues net of purchase power expense increased as a result of favorable weather conditions and increased CTC recoveries.

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 generation 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 revenues and purchased power expense are also affected by fluctuations in participation in the customer choice program. All PECO customers have the choice to purchase energy from a competitive electric generation supplier. The customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy service. Customer choice program activity has no impact on net income. The number of retail customers purchasing energy from a competitive electric generation supplier was 387,600, 36,600 and 21,700 at December 31, 2011, 2010 and 2009, respectively, representing 25%, 2% and 1% of total retail customers, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 57%, 1% and 1% of PECO's retail kWh sales for the years ended December 31, 2011, 2010 and 2009, respectively.

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)
Regulatory program cost recovery	17	—	17
Pricing	139	16	155
Other	(29)	5	(24)
Total increase (decrease)	$ (912)	$ 11	$ (901)

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 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.

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, 2011 compared to the same period in 2010 and normal weather consisted of the following:

Heating and Cooling Degree−Days	2011	2010	Normal	% Change From 2010	% Change 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 operating 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 2 of the Combined Notes to Consolidated Financial Statements for further information regarding energy efficiency initiatives.

The increase in gas operating 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.

Regulatory Program Cost Recovery

The increase in electric revenues net of purchased power expense relating to regulatory program cost recovery was due to increased recovery of costs associated with the energy efficiency and smart meter programs as well as administrative costs for the GSA and AEPS programs. The costs of these programs are recoverable from customers on a full and current basis through approved regulated rates and equal and offsetting expenses are included in operating and maintenance for regulatory required programs, depreciation and amortization expense, and income taxes.

Pricing

The increase in operating revenues net of purchased power and fuel expense as a result of pricing primarily reflected an increase of the new electric and natural gas distribution rates charged to customers that became effective January 1, 2011 in accordance with the 2010 PAPUC approved electric and natural gas distribution rate case settlements. See Note 2 of the Combined Notes to the Consolidated Financial Statements for further information.

Other

The decrease in electric operating revenues net of purchased power expense primarily reflected a decrease in GRT revenue as a result of lower supplied energy service and retail transmission revenues 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.

The changes in PECO's operating revenues net of purchased power and fuel expense for the year ended December 31, 2010 compared to the same period in 2009 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	$ 81	$ (2)	$ 79
CTC recoveries	66	—	66
Regulatory program cost recovery	53	—	53
Pricing	12	—	12
Other	(17)	(1)	(18)
Total increase (decrease)	$ 195	$ (3)	$ 192

Weather

Electric revenues net of purchased power expense were higher due to favorable weather conditions during the summer months of 2010 in PECO's service territory. The increase was partially offset by lower gas revenues net of fuel expense primarily as a result of unfavorable weather conditions in the winters months of 2010 compared to 2009. The changes in heating and cooling degree days for the twelve months ended 2010 and 2009, consisted of the following:

Heating and Cooling Degree−Days (a)	2010	2009	Normal	% Change From 2009	% Change From Normal
Twelve Months Ended December 31,					
Heating Degree−Days	4,396	4,534	4,638	(3.0)%	(5.2)%
Cooling Degree−Days	1,817	1,246	1,292	45.8%	40.6%

CTC Recoveries

The increase in electric revenues net of purchased power expense as a result of CTC recoveries reflected a scheduled increase to the CTC component of the capped generation rates charged to customers, which resulted in a decrease to the energy component and reduced purchase power expense under the PPA. Due to the lower than expected sales volume in 2009, the CTC increase was necessary to ensure full recovery of stranded costs during the final year of the transition period that expired on December 31, 2010.

Regulatory Program Cost Recovery

The increase in electric revenues relating to regulatory program cost recovery was due to the recovery of costs associated with the energy efficiency program and the consumer education program, respectively. 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 for regulatory required programs during the period.

Pricing

The increase in electric revenues net of purchased power expense as a result of pricing reflected an increase in the average price charged to commercial and industrial customers due to decreased usage per customer. The rates charged to customers decrease when usage exceeds a certain threshold.

Other

The decrease in other electric revenues net of purchased power expense primarily reflected decreased transmission revenue earned by PECO as a transmission owner for the use of PECO's transmission facilities in PJM.

The decrease in other gas revenues net of fuel expense primarily reflected lower late payment revenues in 2010 compared to 2009.

Operating and Maintenance Expense

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

	Increase (Decrease)
Labor, other benefits, contracting and materials	$ 26
Storm−related costs	13
Uncollectible accounts expense	4
2010 non−cash charge resulting from Health Care Legislation	(2)
Other	4
Increase in operating and maintenance expense	$ 45

The increase in operating and maintenance expense for 2010 compared to 2009 consisted of the following:

	Increase (Decrease)
Storm−related costs	$ 22
Labor, other benefits, contracting and materials	25
Uncollectible accounts expense	(3)
Severance	(3)
Other	(1)
Increase in operating and maintenance expense	$ 40

Operating and Maintenance for Regulatory Required Programs

Operating and maintenance expense related to regulatory required programs for the years ended December 31, 2011 and 2010 consisted of costs 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 during the current period. The increase in operating and maintenance expense for regulatory required programs for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

	Increase (Decrease) 2011 vs. 2010	Increase (Decrease) 2010 vs. 2009
Smart meter program	$ 9	$ —
EE&C program	2	50
GSA administrative costs	5	—
AEPS administrative costs	1	—
Consumer education program	(1)	3
Increase in operating and maintenance expense for regulatory required programs	$ 16	$ 53

Depreciation and Amortization Expense

The changes in depreciation and amortization expense for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

	Increase (Decrease) 2011 vs. 2010	Increase (Decrease) 2010 vs. 2009
CTC amortization [(a)]	$ (885)	$ 98
Other	27	10
Increase (decrease) in depreciation and amortization expense	$ (858)	$ 108

(a) PECO's scheduled CTC amortization was recorded in accordance with its 1998 restructuring settlement and was fully amortized as of December 31, 2010.

Taxes Other Than Income

The change in taxes other than income for 2011 compared to 2010 and 2010 compared to 2009 consisted of the following:

	Increase (Decrease) 2011 vs. 2010	Increase (Decrease) 2010 vs. 2009
PURTA amortization	$ (4)[(a)]	$ 2[(b)]
GRT expense	(97)[(c)]	22
Other	3	3
Increase (decrease) in taxes other than income	$ (98)	$ 27

(a) 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.
(b) The increase in taxes other than income related to PURTA amortization reflects the impact of regulatory liability amortization recorded in 2009 and 2008 that offsets the distribution rate reduction made to refund the 2007 PURTA settlement to customers.
(c) The decrease in GRT expense for 2011 compared to 2010 was a result of lower operating revenues.

Interest Expense, Net

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 decreased interest expense as a result of 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.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The increase in interest expense, net for 2010 compared to 2009 was primarily due to a change in measurement of uncertain tax positions in accordance with accounting guidance. The increase was partially offset by a decrease in interest expense resulting from the retirement of the PETT transition bonds on September 1, 2010.

See Notes 1 and 11 of the Combined Notes to Consolidated Financial Statements for further information.

Loss in Equity Method Investments

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in the loss in equity method investments for 2010 compared to 2009 was due to the consolidation of PETT in accordance with authoritative guidance for the consolidation of variable interest entities effective January 1, 2010. PETT was dissolved on September 20, 2010. See Note 1 of the Combined Notes to Consolidated Financial Statements for further information.

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 19 of the Combined Notes to Consolidated Financial Statements for additional details of the components of Other, net.

Year Ended December 31, 2010 Compared to Year Ended December 31, 2009. The decrease in Other, net for 2010 compared to 2009 was primarily due to decreased investment income and a decrease in interest income related to a change in measurement of uncertain income tax positions in 2010. See Note 11 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, 2011, 2010 and 2009 were 27.3%, 31.9% and 29.3%, respectively. The decrease in effective income tax rate in 2011 compared to 2010 primarily related to the impact of electing the safe harbor method of tax accounting for electric distribution property. See Note 11 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)	2011	2010	% Change 2011 vs. 2010	Weather–Normal % Change	2009	% Change 2010 vs. 2009	Weather–Normal % Change
Retail Delivery and Sales [(a)]							
Residential	13,687	13,913	(1.6)%	1.7%	12,893	7.9%	0.5%
Small commercial & industrial	8,321	8,503	(2.1)%	(0.7)%	8,397	1.3%	(1.9)%
Large commercial & industrial	15,677	16,372	(4.2)%	(3.3)%	15,848	3.3%	0.8%
Public authorities & electric railroads	945	925	2.2%	4.6%	930	(0.5)%	(0.3)%
Total Electric Retail	38,630	39,713	(2.7)%	(0.9)%	38,068	4.3%	0.1%

	As of December 31,		
Number of Electric Customers	2011	2010	2009
Residential	1,415,681	1,411,643	1,404,416
Small commercial & industrial	157,137	156,865	156,305
Large commercial & industrial	3,110	3,071	3,094
Public authorities & electric railroads	1,122	1,102	1,085
Total	1,577,050	1,572,681	1,564,900

Electric Revenue	2011	2010	% Change 2011 vs. 2010	2009	% Change 2010 vs. 2009
Retail Delivery and Sales [(a)]					
Residential	$1,934	$2,069	(6.5)%	$1,859	11.3%
Small commercial & industrial	584	1,060	(44.9)%	1,034	2.5%
Large commercial & industrial	304	1,362	(77.7)%	1,307	4.2%
Public authorities & electric railroads	38	89	(57.3)%	90	(1.1)%
Total Retail	2,860	4,580	(37.6)%	4,290	6.8%
Other Revenue	249	255	(2.4)%	259	(1.5)%
Total Electric Revenues	$3,109	$4,835	(35.7)%	$4,549	6.3%

(a) Reflects delivery revenues and volumes 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 other wholesale revenue.

Table of Contents

PECO Gas Operating Statistics and Revenue Detail

Deliveries to customers (in mmcf)	2011	2010	% Change 2011 vs. 2010	Weather−Normal % Change	2009	% Change 2010 vs. 2009	Weather−Normal % Change
Retail Delivery and Sales [b]							
Retail sales	54,239	56,833	(4.6)%	1.2%	57,103	(0.5)%	0.9%
Transportation and other	28,204	30,911	(8.8)%	(7.5)%	27,206	13.6%	10.8%
Total Gas Deliveries	82,443	87,744	(6.0)%	(1.8)%	84,309	4.1%	4.1%

Number of Gas Customers	As of December 31, 2011	2010	2009
Residential	451,382	448,391	444,923
Commercial & industrial	41,373	41,303	40,991
Total Retail	492,755	489,694	485,914
Transportation	879	838	778
Total	493,634	490,532	486,692

Gas revenue	2011	2010	% Change 2011 vs. 2010	2009	% Change 2010 vs. 2009
Retail Delivery and Sales [a]					
Retail sales	$575	$656	(12.3)%	$732	(10.4)%
Transportation and other	36	28	28.6%	30	(6.7)%
Total Gas Deliveries	$611	$684	(10.7)%	$762	(10.2)%

(a) Reflects delivery revenues and volumes 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. The cost of natural gas is charged to customers purchasing natural gas from PECO.

Liquidity and Capital Resources

The Registrants’ operating and capital expenditures requirements are provided by internally generated cash flows from operations as well as funds from external sources in the capital markets and through bank borrowings. The Registrants’ businesses are capital intensive and require considerable capital resources. Each Registrant’s access to external financing on reasonable terms depends on its credit ratings and current overall capital market business conditions, including that of the utility industry in general. If these conditions deteriorate to the extent that the Registrants no longer have access to the capital markets at reasonable terms, Exelon, Generation, ComEd and PECO have access to unsecured revolving credit facilities with aggregate bank commitments of $0.5 billion, $5.3 billion, $1.0 billion and $0.6 billion, respectively. Additionally, Generation has access to a supplemental credit facility with an aggregate available commitment of $0.3 billion. The Registrant’s credit facilities extend through March 2016 for Exelon, Generation and PECO and March 2013 for ComEd. Availability under the supplemental facility extends through December 2015 for $150 million of the $300 million commitment and March 2016 for the remaining $150 million. Exelon, Generation, ComEd and PECO utilize their credit facilities to support their commercial paper programs, provide for other short−term borrowings and to issue letters of credit. See the “Credit Matters” section below for further discussion. The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

The Registrants primarily use their capital resources, including cash, to fund capital requirements, including construction expenditures, retire debt, pay dividends, fund pension and other postretirement benefit obligations and invest in new and existing ventures. The Registrants spend a significant amount of cash on capital improvements and construction projects that have a long−term return on investment. Additionally, ComEd and PECO 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 10 of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

Proposed Merger Commitments

As part of the application for approval of the merger by the MDPSC and related settlements, Exelon and Constellation have proposed a package of benefits to Baltimore Gas and Electric Company customers, the City of Baltimore and the State of Maryland, which results in a direct investment, including capital projects, in the State of Maryland of more than $1 billion. Exelon will evaluate the funding sources for these commitments at the time the specific investments or contributions are made. The funding may be through a combination of cash on the balance sheet, cash from operations or external financing. Of the $1 billion, Exelon estimates that approximately $150−200 million will be funded in 2012 with the remainder funded in 2013 and beyond. See Note 3 of the Combined Notes to Consolidated Financial Statements for further discussion of the proposed merger with Constellation.

Cash Flows from Operating Activities

General

Generation's cash flows from operating activities primarily result from the sale of electric energy to wholesale 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 and PECO's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO, gas distribution services. ComEd's and PECO's distribution services are provided to an established and diverse base of retail customers. ComEd's and PECO'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, and their ability to achieve operating cost reductions. See Notes 2 and 18 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 $139 million to its pension plans in 2012, of which Generation, ComEd and PECO expect to contribute $60 million, $22 million and $16 million, respectively. Exelon contributed approximately $2.1 billion to its pension plans in January 2011 of which Generation, ComEd and PECO contributed $954 million, $873 million and $110 million, respectively. Exelon funded the $2.1 billion contribution with approximately $500 million from cash from operations, $750 million from the tax benefits of making the pension contributions and $850 million associated with the accelerated cash tax benefits from the 100% bonus depreciation provision enacted as part of the Tax Relief Act of 2010. Exelon contributed $766 million and $441 million to its pension plans in 2010 and 2009, respectively. See Note 13 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2011 and 2010 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 $302 million to the other postretirement benefit plans in 2012, of which Generation, ComEd and PECO expect to contribute $132 million, $114 million and $34 million, respectively. Exelon contributed $277 million, $213 million and $167 million in 2011, 2010 and 2009, respectively. These amounts do not reflect Federal prescription drug subsidy payments received of $11 million, $10 million and $10 million in 2011, 2010 and 2009, respectively. See Note 13 of the Combined Notes to Consolidated Financial Statements for the Registrants' 2011 and 2010 other postretirement benefit contributions.

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

Tax Matters

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

- In the third quarter of 2010, Exelon and IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012, and that Exelon will receive additional tax refunds of approximately $365 million between 2012 and 2014. In order to stop additional interest from accruing on the IRS expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. During 2010, Exelon and IRS Appeals failed to reach a settlement with respect to the like−kind exchange position and the related substantial understatement penalty. See Note 11 of the Combined Notes to Consolidated Financial Statements for additional information regarding potential cash flows impacts of a fully successful IRS challenge to Exelon's like−kind exchange position.

- On August 19, 2011, the IRS issued Revenue Procedure 2011−43 that provides a safe harbor method of tax accounting for electric transmission and distribution property. ComEd intends to adopt the safe harbor in the Revenue Procedure in future periods as the associated tax cash benefits are received for the 2011 tax year. PECO adopted the safe harbor for the 2010 tax year. This change to the newly prescribed method will result in an initial cash tax benefit (primarily in 2011) at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million. See Note 2 of the Combined Notes to Consolidated Financial Statements 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. The IRS anticipates issuing guidance in 2012 on the appropriate tax treatment of repair costs for gas distribution assets. Upon issuance of this guidance, PECO will assess its impact, and if it results in a cash benefit to Exelon, PECO will file a request for change in method of tax accounting for repair costs. PECO's approved 2010 natural gas distribution rate case settlement stipulates that the expected cash benefit resulting from the application of the new methodology to prior tax years must be refunded to customers over a seven−year period. The prospective tax benefit claimed as a result of the new methodology should be reflected in tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next natural gas distribution base rate case.

- The Tax Relief Act of 2010, enacted into law on December 17, 2010, includes provisions accelerating the depreciation of certain property for tax purposes. Qualifying property placed into service after September 8, 2010, and before January 1, 2012, is eligible for 100% bonus depreciation. Additionally, qualifying property placed into service during 2012 is eligible for

50% bonus depreciation. These provisions will generate approximately $1.1 billion of cash for Exelon (approximately $850 million in 2011 and approximately $300 million in 2012). The cash generated is an acceleration of tax benefits that Exelon would have otherwise received over 20 years. Additionally, while the capital additions at ComEd and PECO generally increase future revenue requirements, the bonus depreciation associated with these capital additions will partially mitigate any future rate increases through the ratemaking process. See the “Pension and Other Postretirement Benefits” section above for further details regarding the use of the cash generated under the Tax Relief Act of 2010.

- 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. See Note 11 of the Combined Notes to Consolidated Financial Statements for further details regarding the 2011 Illinois State Tax Rate Legislation, which increases the corporate income tax rate in Illinois.

The following table provides a summary of the major items affecting Exelon’s cash flows from operations for the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2011 vs. 2010 Variance	2009	2010 vs. 2009 Variance
Net income	$ 2,495	$2,563	$ (68)	$2,707	$ (144)
Add (subtract):					
Non−cash operating activities (a)	4,848	4,340	508	3,930	410
Pension and non−pension postretirement benefit contributions	(2,360)	(959)	(1,401)	(588)	(371)
Income taxes	492	(543)	1,035	(29)	(514)
Changes in working capital and other noncurrent assets and liabilities (b)	(275)	122	(397)	(82)	204
Option premiums paid, net	(3)	(124)	121	(40)	(84)
Counterparty collateral received (paid), net	(344)	(155)	(189)	196	(351)
Net cash flows provided by operations	$ 4,853	$5,244	$ (391)	$6,094	$ (850)

(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 2011, 2010 and 2009 by Registrant were as follows:

	2011	2010	2009
Exelon	$4,853	$5,244	$6,094
Generation	3,313	3,032	3,930
ComEd	836	1,077	1,020
PECO	818	1,150	1,166

Changes in Exelon’s, Generation’s, ComEd’s and PECO’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 2011, 2010 and 2009 were as follows:

Generation

- During 2011, 2010 and 2009, Generation had net (payments) receipts of counterparty collateral of $(410) million, $(1) million and $195 million, respectively. Net payments during 2011 and 2010 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 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 and $118 million in 2009. As of December 31, 2010, Generation had fulfilled its commitments under the Illinois Settlement Legislation.
- During 2011, 2010 and 2009, Generation’s accounts receivable from ComEd increased (decreased) by $12 million, $(65) million and $(28) million, respectively, primarily due to changes in receivables for energy purchases related to its SFC, ICC−approved RFP contracts and financial swap contract.
- During 2011, 2010 and 2009, Generation’s accounts receivable from PECO primarily due to the PPA increased (decreased) by $(210) million, $74 million and $48 million, respectively.
- During 2011, 2010 and 2009, Generation had net payments of approximately $3 million, $124 million and $40 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 2011, 2010 and 2009, 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 $12 million, $(65) million and $(28) million, respectively. During 2011, 2010 and 2009, ComEd’s payables to other energy suppliers for energy purchases increased (decreased) by $(43) million, $58 million and $(68) million, respectively.
- During 2011 and 2010, ComEd received $63 million and posted $153 million, respectively, of incremental cash collateral with PJM due to seasonal variations in its energy transmission activity levels. As of December 31, 2011 and December 31, 2010, ComEd had $90 million and $153 million of cash collateral remaining at PJM. Prior to the second quarter of 2010, ComEd used letters of credit to cover all PJM collateral requirements.

PECO

- During 2011, 2010 and 2009, PECO’s payables to Generation for energy purchases increased (decreased) by $(210) million, $74 million and $48 million, respectively, and payables to other energy suppliers for energy purchases increased (decreased) by $97 million, $1 million and $(43) million, respectively. PECO’s decrease in payables to Generation and increase in payables to other energy suppliers in 2011 is due to the expiration of the PPA with Generation on December 31, 2010.

[Table of Contents](#)

Cash Flows from Investing Activities

Cash flows used in investing activities for 2011, 2010, and 2009 by Registrant were as follows:

	2011	2010	2009
Exelon [(a)(b)(d)]	$(4,603)	$(3,894)	$(3,458)
Generation [(a)(d)]	(3,077)	(2,896)	(2,220)
ComEd [(b)]	(1,007)	(939)	(821)
PECO	(557)	(120)	(377)

Capital expenditures by Registrant for 2011, 2010 and 2009 and projected amounts for 2012 are as follows:

	Projected 2012 [(c)]	2011	2010	2009
Generation [(d)]	$ 3,768	$2,491	$1,883	$1,977
ComEd [(e)]	1,330	1,028	962	854
PECO	436	481	545	388
Other [(f)]	48	42	(64)	54
Total Exelon capital expenditures	$ 5,582	$4,042	$3,326	$3,273

(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 3 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) The projected capital expenditures do not include adjustments for non−cash activity.
(d) Includes nuclear fuel.
(e) The projected capital expenditures include $233 million in incremental spending related to ComEd's 2012 investment plan filed with the ICC on January 6, 2012. Pursuant to EIMA, under which ComEd has committed to invest approximately $2.6 billion over the next ten years to modernize and storm−harden its distribution system and to implement smart grid technology.
(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 34% and 31% of the projected 2012 capital expenditures at Generation are for investments in renewable energy generation, including Antelope Valley and Exelon Wind construction costs; and the acquisition of nuclear fuel, 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 2012 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.

ComEd and PECO

Approximately 80% and 69% of the projected 2012 capital expenditures at ComEd and PECO, 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 and PECO's construction commitments under PJM's RTEP. The remaining amounts are for capital additions to support new business and customer growth, which for ComEd includes capital expenditures related to smart grid/smart meter technology required under EIMA and for PECO includes capital expenditures related to its smart meter program and SGIG project, net of DOE expected reimbursements. See Notes 2 and 5 of the Combined Notes to Consolidated Financial Statements for additional information.

In 2010, NERC provided guidance to transmission owners that recommends ComEd and PECO 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 and PECO submitted their most recent bi−annual reports to NERC in January 2012. ComEd and PECO will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's and PECO's forecasted 2012 capital expenditures above reflect capital spending for remediation pursuant to the assessments completed as of December 31, 2011.

ComEd and PECO 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 2 of the Combined Notes to Consolidated Financial Statements.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for 2011, 2010 and 2009 by Registrant were as follows:

	2011	2010	2009
Exelon	$(846)	$(1,748)	$(1,897)
Generation	(196)	(779)	(1,746)
ComEd	355	(179)	(155)
PECO	(589)	(811)	(525)

Debt. Debt activity for 2011, 2010 and 2009 by Registrant was as follows:

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, retire $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, retire $345 million of First Mortgage Bonds, Series 105, and for other general corporate purposes.

Table of Contents

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	Issuances of long−term debt in 2009	Use of proceeds
Generation	$46 million of 3−year term rate Pollution Control Notes at 5.00% with a final maturity of December 1, 2042	Used to refinance $46 million of unenhanced tax−exempt variable rate debt that was repurchased on February 23, 2009. (a)
Generation	$1.5 billion of Senior Notes, consisting of $600 million of Senior Notes at 5.20% due October 1, 2019 and $900 million Senior Notes at 6.25% due October 1, 2039	Used to finance the purchase and optional redemption of Generation’s 6.95% bonds due in 2011 and for general corporate purposes, including a distribution to Exelon to fund the purchase and optional redemption of Exelon’s 6.75% Notes due in 2011 and to fun
ComEd	$50 million of tax−exempt variable−rate First Mortgage Bonds, Series 2008 D due March 1, 2020 (b)	Used to repay credit facility borrowings incurred to repurchase bonds. (c)
ComEd	$50 million of tax−exempt variable−rate First Mortgage Bonds, Series 2008 E due March 21, 2021 (b)	Used to repay credit facility borrowings incurred to repurchase bonds. (c)
ComEd	$91 million of tax−exempt variable−rate First Mortgage Bonds, Series 2008 F due May 1, 2017 (b)	Used to repay credit facility borrowings incurred to repurchase bonds. (c)
PECO	$250 million of First and Refunding Mortgage Bonds at 5.00% due October 1, 2014	Used to refinance short−term debt and for other general corporate purposes.

(a) Repurchase required due to failed remarketing.
(b) Remarketed in May 2009 with letter of credit issued under credit facility.
(c) Repurchase required due to expiration of existing letter of credit.

Company	Retirement of long−term debt in 2011
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

Company	Retirement of long−term debt in 2011
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

Company	Retirement of long−term debt in 2010
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

Company	Retirement of long−term debt in 2009
Exelon Corporate	$500 million of 6.75% Senior Notes, due May 1, 2011
Generation	$700 million of 6.95% Senior Notes, due June 15, 2011
Generation	$46 million of Pollution Control Notes with variable interest rates, due December 1, 2042 [a]
Generation	$51 million of Pollution Control Notes with variable interest rates, due April 1, 2021
Generation	$39 million of Pollution Control Notes with variable interest rates, due April 1, 2021
Generation	$30 million of Pollution Control Notes with variable interest rates, due December 1, 2029
Generation	$92 million of Pollution Control Notes with variable interest rates, due October 1, 2030
Generation	$69 million of Pollution Control Notes with variable interest rates, due October 1, 2030

Table of Contents

Company	Retirement of long−term debt in 2009
Generation	$14 million of Pollution Control Notes with variable interest rates, due October 1, 2034
Generation	$13 million of Pollution Control Notes with variable interest rates, due October 1, 2034
Generation	$10 million of 6.33% notes payable, due August 8, 2009
Generation	$1 million scheduled payments of 7.83% Kennett Square capital lease until September 20, 2020
ComEd	$91 million tax−exempt variable−rate First Mortgage Bonds, Series 2008 F, due March 1, 2017 (b)
ComEd	$50 million tax−exempt variable−rate First Mortgage Bonds, Series 2008 D, due March 1, 2020 (b)
ComEd	$50 million tax−exempt variable−rate First Mortgage Bonds, Series 2008 E, due May 21, 2021 (b)
ComEd	$16 million of 5.70% First Mortgage Bonds, Series 1994 B, due January 15, 2009
ComEd	$1 million of 4.625−4.75% sinking fund debentures, due at various dates
PECO	$319 million of 7.65% PETT Transition Bonds, due September 1, 2009
PECO	$390 million of 6.52% PETT Transition Bonds, due September 1, 2010

(a) Repurchased due to a failed remarketing and remarketed in February 2009.
(b) First Mortgage Bonds issued under the ComEd mortgage indenture to secure variable weekly−rate tax−exempt pollution controls bonds. Repurchased due to expiration of existing letter of credit and remarketed in May 2009.

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 2011, 2010 and 2009 by Registrant were as follows:

	2011	2010	2009
Exelon	$1,393	$1,389	$1,385
Generation	172	1,508	2,276
ComEd	300	310	240
PECO	352	228	316

First Quarter 2012 Dividend. On October 25, 2011, the Exelon Board of Directors declared a first quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock payable on March 9, 2012, to shareholders of record of Exelon at the end of the day on February 15, 2012.

Second Quarter 2012 Dividend. In addition, on January 24, 2012, the Exelon Board of Directors declared a second quarter 2012 regular quarterly dividend of $0.525 per share on Exelon's common stock contingent on the pending merger with Constellation. If the effective date of the merger is after May 15, 2012, the Board of Directors declared a regular quarterly dividend of $0.525 per share on Exelon's common stock, payable on June 8, 2012, to shareholders of record of Exelon at the end of the day on May 15, 2012.

If the effective date of the merger is on or before May 15, 2012, shareholders will receive two separate dividend payments totaling $0.525 per share:

- The first of the dividend payments will be pro−rated, with shareholders of record as of the end of day before the effective date of the merger receiving $0.00583 per share per day for the period from and including February 16, 2012, the day after the record date for the previous dividend, through and including the day before the effective date of the merger. This portion of the dividend will be paid within 30 days after the effective date of the merger.

- The second of the dividend payments will also be pro−rated, with all Exelon shareholders, including the former Constellation shareholders, of record at the end of the day on May 15, 2012, receiving $0.00583 per share per day for the period from and including the effective date of the merger through and including May 15, 2012. This portion of the dividend will be paid on June 8, 2012.

Short−Term Borrowings. Short−term borrowings incurred (repaid) during 2011, 2010 and 2009 by Registrant were as follows:

	2011	2010	2009
ComEd	$—	$(155)	$ 95
PECO(a)	—	—	(95)
Other	161	—	(56)
Exelon	$161	$(155)	$(56)

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

Retirement of Long−Term Debt to Financing Affiliates. Retirement of long−term debt to financing affiliates during 2011, 2010 and 2009 by Registrant were as follows:

	2011	2010	2009
Exelon	$ —	$ —	$ 709
PECO	—	—	709

Contributions from Parent/Member. Contributions from Parent/Member (Exelon) during 2011, 2010 and 2009 by Registrant were as follows:

	2011	2010	2009
Generation	$ 30	$ 62	$ 57
ComEd(a)	—	2	8
PECO	18	223	347

(a) $180 million and $320 million for the years ended December 31, 2010 and 2009, respectively, reflect payments received to reduce the receivable from parent, which was completely repaid as of December 31, 2010.

Other. Other significant financing activities for Exelon for 2011, 2010 and 2009 were as follows:

- Exelon received proceeds from employee stock plans of $38 million, $48 million and $42 million during 2011, 2010 and 2009, 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 $7.7 billion in aggregate total commitments of which $6.8 billion was available as of December 31, 2011, and of which no financial institution has more than 10% of the aggregate commitments for Exelon, Generation, ComEd and PECO. The Registrants had access to the commercial paper market during 2011 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, 2011, it would have been required to provide incremental collateral of approximately $1,819 million, which is well within its current available credit facility capacities of approximately $4.7 billion. The $1,819 million includes $1,612 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 and $207 million of financial assurances that Generation would be required to provide NEIL related to annual retrospective premium obligations. If ComEd lost its investment grade credit rating as of December 31, 2011, it would have been required to provide incremental collateral of approximately $227 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, 2011, it would have been required to provide collateral of $1 million pursuant to PJM’s credit policy and could have been required to provide collateral of approximately $54 million related to its natural gas procurement contracts, which, in the aggregate, is well within PECO’s current available credit facility capacity of approximately $600 million.

Exelon Credit Facilities

See Note 10 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, 2011, the capital structures of the Registrants consisted of the following:

	Exelon	Generation	ComEd	PECO
Long−term debt	45%	30%	44%	37%
Long−term debt to affiliates (a)	2	—	2	3
Common equity	52	—	54	54
Member’s equity	—	70	—	—
Preferred securities	—	—	—	2
Commercial paper and notes payable	1	—	—	4

(a) Includes approximately $390 million, $206 million and $184 million owed to unconsolidated affiliates of Exelon, ComEd and PECO, respectively, that 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 and PECO. See Note 1 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. 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 2011 are described in the following table in addition to the net contribution or borrowing as of December 31, 2011:

	Maximum Contributed	Maximum Borrowed	December 31, 2011 Contributed (Borrowed)
Generation	$ —	$ 335	$ —
PECO	465	—	82
BSC	—	220	(82)
Exelon Corporate	261	N/A	—

Shelf Registration Statements. Each of the Registrants has a current shelf registration statement effective with the SEC that provides for the sale of unspecified amounts of securities. The ability of each Registrant to sell securities off its 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 and PECO of long−term debt or equity securities requires the prior authorization of the ICC and PAPUC, respectively. ComEd and PECO 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. As of December 31, 2011, ComEd had $41 million in long−term debt refinancing authority from the ICC and $456 million in new money long−term debt financing authority. As of December 31, 2011, PECO had $1.9 billion in long−term debt financing authority from the PAPUC.

FERC has financing jurisdiction over ComEd’s and PECO’s short−term financings and all of Generation’s financings. As of December 31, 2011, 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. Generation currently has blanket financing authority that it received from FERC in connection with its market−based rate authority. See Note 2 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. At December 31, 2011, Exelon had retained earnings of $10,055 million, including Generation’s undistributed earnings of $4,232 million, ComEd’s retained earnings of $447 million consisting of retained earnings appropriated for future dividends of $2,086 million partially offset by $1,639 million of unappropriated retained deficit, and PECO’s retained earnings of $559 million. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information regarding fund transfer restrictions.

Table of Contents

Contractual Obligations and Off−Balance Sheet Arrangements

The following tables summarize the Registrants' future estimated cash payments as of December 31, 2011 under existing contractual obligations, including payments due by period. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the Registrants' commercial and other commitments, representing commitments potentially triggered by future events.

Exelon

		Payment due within				
	Total	2012	2013−2014	2015−2016	Due 2017 and beyond	All Other
Long−term debt (a)	$13,000	$ 825	$1,919	$1,725	$ 8,531	$—
Interest payments on long−term debt (b)	8,454	663	1,197	1,023	5,571	—
Liability and interest for uncertain tax positions (c)	191	1	—	—	—	190
Capital leases (d)	34	3	6	7	18	—
Operating leases (e)	669	72	118	92	387	—
Purchase power obligations (f)	922	188	134	122	478	—
Fuel purchase agreements (f)	8,722	1,491	2,092	1,870	3,269	—
Electric supply procurement (f)	682	469	193	20	—	—
REC and AEC purchase commitments (f)	15	3	5	2	5	—
Curtailment services commitments (g)	13	13	—	—	—	—
Long−term renewable energy and REC commitments (h) (i)	1,692	36	142	153	1,361	—
Other purchase obligations (j)	595	282	232	66	15	—
City of Chicago agreement—2003	6	6	—	—	—	—
Spent nuclear fuel obligation (k)	1,019	—	—	—	1,019	—
Pension minimum funding requirement	1,950	96	239	1,352	263	—
Total contractual obligations	$37,964	$4,148	$6,277	$6,432	$ 20,917	$190

(a) Includes $390 million due after 2016 to ComEd and PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 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, 2011. Includes estimated interest payments due to ComEd and PECO financing trusts.
(c) As of December 31, 2011, Exelon's liability for uncertain tax positions and related net interest payable were $191 million and $10 million, respectively. Exelon was unable to reasonably estimate the timing of liability and interest payments 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 11 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 that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2011. 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 2 and 18 of the Combined Notes to Consolidated Financial Statements.
(f) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, nuclear fuel and purchase AECs and curtailment services. See Note 18 of the Combined Notes to Consolidated Financial Statements for electric and gas purchase commitments.

Table of Contents

(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 2 of Combined Notes to Consolidated Financial Statements for additional information.
(h) Commitments for services, materials and information technology.
(i) Excludes obligations associated with the January 25, 2012 materials agreement between ComEd and Silver Springs Network, Inc. (Silver Spring) by which Silver Spring will deliver a smart grid platform to ComEd's system. ComEd has the right to terminate the agreement upon written notice to Silver Spring if ComEd fails to obtain required regulatory approvals, including ICC approval of ComEd's AMI Deployment Plan associated with EIMA.
(j) In 2003, ComEd entered separate agreements with the City of Chicago and with Midwest Generation. Under the terms of the agreements, ComEd will pay the City of Chicago $60 million over ten years to be relieved of a requirement, originally transferred to Midwest Generation upon the sale of ComEd's fossil stations in 1999, to build a 500−MW generation facility.
(k) 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. These amounts represent estimates that are based on assumptions that are subject to change. The minimum required contributions for years after 2016 are currently not reliably estimable. See Note 13 of the Combined Notes to Consolidated Financial Statements for further information regarding estimated future pension benefit payments.

Generation

		Payment due within				
	Total	2012	2013−2014	2015−2016	Due 2017 and beyond	All Other
Long−term debt	$ 3,648	$ —	$ 500	$ —	$ 3,148	$—
Interest payments on long−term debt (a)	2,999	202	378	351	2,068	—
Liability and interest for uncertain tax benefits (b)	110	—	—	—	—	110
Capital leases	34	3	6	7	18	—
Operating leases (c)	432	29	54	54	295	—
Purchase power obligations (d)	922	188	134	122	478	—
Fuel purchase agreements (e)	8,211	1,317	1,935	1,783	3,176	—
Other purchase obligations (f)	388	139	178	64	7	—
Spent nuclear fuel obligation	1,019	—	—	—	1,019	—
Total contractual obligations	$17,763	$1,878	$3,185	$2,381	$ 10,209	$110

(a) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 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, 2011.
(b) As of December 31, 2011, Generation's liability for uncertain tax positions was $110 million. Generation was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(c) Excludes PPAs and other capacity contracts that are accounted for as operating leases. These amounts are included within purchase power obligations.
(d) Purchase power obligations include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented represent Generation's expected payments under these arrangements at December 31, 2011. Expected payments include certain capacity charges that are contingent on plant availability. Expected payments exclude renewable PPA contracts that are contingent in nature. See Note 18 of the Combined Notes to Consolidated Financial Statements.
(e) See Note 18 of the Combined Notes to Consolidated Financial Statements for further information regarding fuel purchase agreements.
(f) Commitments for services, materials and information technology.

ComEd

	Total	Payment due within 2012	2013–2014	2015–2016	Due 2017 and beyond	All Other
Long–term debt [(a)]	$ 5,893	$ 450	$ 869	$ 925	$ 3,649	$ —
Interest payments on long–term debt [(b)]	3,380	280	507	456	2,137	—
Liability and interest for uncertain tax positions [(c)]	70	—	—	—	—	70
Operating leases	125	15	26	23	61	—
2003 City of Chicago agreement [(d)]	6	6	—	—	—	—
Electric supply procurement	678	207	471	—	—	—
REC purchase commitments	1	1	—	—	—	—
Long–term renewable energy and associated REC commitments [(e)]	1,692	36	142	153	1,361	—
Other purchase obligations [(f) (g)]	51	48	3	—	—	—
Total contractual obligations	$ 11,896	$ 1,043	$ 2,018	$ 1,557	$ 7,208	$ 70

(a) Includes $206 million due after 2016 to a ComEd financing trust.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 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, 2011. Includes estimated interest payments due to the ComEd financing trust.
(c) As of December 31, 2011, ComEd's liability for uncertain tax positions was $70 million. ComEd was unable to reasonably estimate the timing of liability and interest payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) In 2003, ComEd entered into separate agreements with the City of Chicago and with Midwest Generation. Under the terms of the agreements, ComEd will pay the City of Chicago $60 million over ten years to be relieved of a requirement, originally transferred to Midwest Generation upon the sale of ComEd's fossil stations in 1999, to build a 500–MW generation facility.
(e) 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 2 of Combined Notes to Consolidated Financial Statements for additional information.
(f) Other purchase commitments include commitments for services, materials and information technology.
(g) Excludes obligations associated with the January 25, 2012 materials agreement between ComEd and Silver Springs Network, Inc. (Silver Spring) by which Silver Spring will deliver a smart grid platform to ComEd's system. ComEd has the right to terminate the agreement upon written notice to Silver Spring if ComEd fails to obtain required regulatory approvals, including ICC approval of ComEd's AMI Deployment Plan associated with EIMA.

PECO

	Total	Payment due within 2012	2013–2014	2015–2016	Due 2017 and beyond	All Other
Long–term debt [(a)]	$ 2,159	$ 375	$ 550	$ —	$ 1,234	$ —
Interest payments on long–term debt [(b)]	1,272	114	177	142	839	—
Liability and interest for uncertain tax positions [(c)]	4	1	—	—	—	3
Operating leases	57	21	30	6	—	—
Fuel purchase agreements [(d)]	511	174	157	87	93	—
Electric supply procurement [(d)]	1,088	760	303	25	—	—
AEC purchase commitments [(d)]	39	7	20	4	8	—
Curtailment services commitments [(d)]	13	13	—	—	—	—
Other purchase obligations [(e)]	98	53	35	2	8	—
Total contractual obligations	$ 5,241	$ 1,518	$ 1,272	$ 266	$ 2,182	$ 3

(a) Includes $184 million due after 2017 to PECO financing trusts.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) As of December 31, 2011, PECO's liability for uncertain tax positions was $4 million. PECO was unable to reasonably estimate the timing of certain liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions.
(d) Represents commitments to purchase natural gas and related transportation, storage capacity and services, procure electric supply, and purchase AECs and curtailment services. See Note 18 of the Combined Notes to Consolidated Financial Statements for additional information.
(e) Commitments for services, materials and information technology.

See Note 18 of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' other commitments potentially triggered by future events.

For additional information regarding:

- commercial paper, see Note 10 of the Combined Notes to Consolidated Financial Statements.
- long−term debt, see Note 10 of the Combined Notes to Consolidated Financial Statements.
- liabilities related to uncertain tax positions, see Note 11 of the Combined Notes to Consolidated Financial Statements.
- capital lease obligations, see Note 10 of the Combined Notes to Consolidated Financial Statements.
- operating leases, energy commitments, fuel purchase agreements, construction commitments and rate relief commitments, see Note 18 of the Combined Notes to Consolidated Financial Statements.
- the nuclear decommissioning and SNF obligations, see Notes 12 and 18 of the Combined Notes to Consolidated Financial Statements.
- regulatory commitments, see Note 2 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 18 of the Combined Notes to Consolidated Financial Statements.
- new accounting pronouncements, see Note 1 of the Combined Notes to Consolidated Financial Statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Registrants are exposed to market risks associated with adverse changes in commodity prices, counterparty credit, interest rates and equity prices. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, 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.

Commodity Price Risk (Exelon, Generation, ComEd and PECO)

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 and PECO'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 2012 through 2014. Generation's energy contracts are accounted for under the accounting guidance for derivatives as further discussed in Note 9 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, 2011, the percentage of expected generation hedged was 88%−91%, 61%−64% and 32%−35% for 2012, 2013 and 2014, 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 cash flow hedges, other derivatives and certain non−derivative contracts including sales to ComEd and PECO 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 non−trading portfolio associated with a $5 reduction in the annual average Ni−Hub and PJM−West around−the−clock energy price based on December 31, 2011 market conditions and hedged position would be a decrease in pre−tax net income of approximately $45 million, $289 million and $535 million, respectively, for 2012, 2013 and 2014. 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 purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The 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 5,742 GWh, 3,625 GWh and 7,578 GWh for the years ended December 31, 2011, 2010 and 2009 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, 2011 resulted in pre−tax gains of $24 million due to net mark−to−market losses of $3 million and realized gains of $27 million. Generation uses a 95% confidence interval, one day holding period, one−tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged $80,000 of exposure over the last 18 months. 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, 2011 of $6,858 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 55% of Generation's uranium concentrate requirements from 2012 through 2016 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 18 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.

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 begins 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 2 and 9 of the Combined Notes to Consolidated Financial Statements for additional information regarding energy procurement and derivatives.

PECO

Prior to January 1, 2011, PECO had transferred substantially all of its commodity price risk related to its procurement of electric supply to Generation through a PPA that expired on December 31, 2010. The PPA was not considered a derivative under current authoritative derivative guidance. Pursuant to PECO's PAPUC−approved DSP Program, PECO began to procure electric supply for default service customers in June 2009 for the post−transition period beginning on January 1, 2011 through block contracts and full requirements contracts. PECO's full requirements contracts and block contracts that are considered derivatives qualify for the normal purchases and normal sales exception under current authoritative derivative guidance. Under the DSP Program, PECO is permitted to recover its electricity procurement costs from retail customers without mark−up.

Table of Contents
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 9 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, 2010 to December 31, 2011. 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 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, 2011 and December 31, 2010 refer to Note 9 of the Combined Notes to Consolidated Financial Statements.

	Generation	ComEd	PECO	Intercompany Eliminations (g)	Exelon
Total mark−to−market energy contract net assets (liabilities) at January 1, 2010 [a]	$ 1,769	$ (971)	$ (4)	$ —	$ 794
Total change in fair value during 2010 of contracts recorded in result of operations	415	—	—	—	415
Reclassification to realized at settlement of contracts recorded in results of operations [b]	(328)	—	—	—	(328)
Ineffective portion recognized in income	1	—	—	—	1
Reclassification to realized at settlement from accumulated OCI [c]	(1,125)	—	—	371	(754)
Effective portion of changes in fair value—recorded in OCI [d]	883	—	—	(378)	505
Changes in fair value—energy derivatives [e]	—	—	(5)	7	2
Changes in collateral	(4)	—	—	—	(4)
Changes in net option premium paid/(received) [f]	124	—	—	—	124
Other income statement reclassifications	73	—	—	—	73
Other balance sheet reclassifications	(5)	—	—	—	(5)
Total mark−to−market energy contract net assets (liabilities) at December 31, 2010 [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 [b]	(541)	—	—	—	(541)
Ineffective portion recognized in income	9	—	—	—	9
Reclassification to realized at settlement from accumulated OCI [c]	(968)	—	—	456	(512)

	Generation	ComEd	PECO	Intercompany Eliminations (g)	Exelon
Effective portion of changes in fair value—recorded in OCI [d]	827	—	—	(170)	657
Changes in fair value—energy derivatives [e]	—	171	9	(286)	(106)
Changes in collateral	411	—	—	—	411
Changes in net option premium paid/(received) [f]	3	—	—	—	3
Other income statement reclassifications	(137)	—	—	—	(137)
Other balance sheet reclassifications	—	—	—	—	—
Total mark−to−market energy contract net assets (liabilities) at December 31, 2011 [a]	$ 1,648	$ (800)	$ —	$ —	$ 848

(a) Amounts are shown net of collateral paid to and received from counterparties.
(b) For Generation, reflects $9 million and $1 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, 2011 and 2010, respectively.
(c) For Generation, includes $451 million and $371 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, 2011 and 2010, 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 $170 million and $375 million of gains related to the changes in fair value of the five−year financial swap with ComEd for the years ended December 31, 2011 and 2010, respectively, and $3 million of gains related to the changes in fair value of the block contracts with PECO for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, no additional changes in the fair value of PECO's block contracts were recorded and the mark−to−market balances previously recorded were amortized over the terms of the contracts, which ended December 31, 2011.
(e) For ComEd and PECO, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of December 31, 2011 and 2010, ComEd recorded a regulatory asset of $800 million and $975 million, respectively, related to its mark−to−market derivative liabilities with Generation and unaffiliated suppliers. As of December 31, 2010, ComEd also had a regulatory liability of $4 million related to mark−to−market derivative assets with unaffiliated suppliers. During 2011 and 2010, this includes $170 million and $375 million of decreases in fair value, respectively, and $451 million and $371 million of realized gains, respectively, due to settlements of ComEd's five−year financial swap with Generation. During 2011 and 2010 ComEd also recorded a $110 million decrease and a $4 million increase, respectively, in fair value associated with floating−to−fixed energy swap contracts with unaffiliated suppliers. As of December 31, 2010, PECO recorded a regulatory asset of $9 million related to its mark−to−market derivative liabilities. During the year ended December 31, 2010, PECO's change included $3 million related to the change in fair value of PECO's block contracts with Generation. PECO's block contracts were designated as normal sales as of May 31, 2010 and, as such, no additional changes in the fair value of PECO's block contracts were recorded. 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.
(f) Includes $137 million and $73 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, 2011 and 2010, respectively.
(g) Amounts related to the five−year financial swap between Generation and ComEd and the block contracts between Generation and PECO are eliminated in consolidation.

Fair Values

The following tables present maturity and source of fair value of the Registrants mark−to−market energy 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). Second, the tables show the maturity, by year, of the Registrants' energy contract net assets (liabilities), giving an indication of when these mark−to−market amounts will settle and either generate or require cash. See Note 8 of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

Exelon

	Maturities Within 2012	2013	2014	2015	2016	2017 and Beyond	Total Fair Value
Normal Operations, qualifying cash flow hedge contracts [(a)(c)]:							
Prices provided by external sources	$339	$246	$ 99	$ 1	$—	$ —	$ 685
Total	$339	$246	$ 99	$ 1	$—	$ —	$ 685
Normal Operations, other derivative contracts [(b)(c)]:							
Actively quoted prices	$ (1)	$—	$—	$—	$—	$ —	$ (1)
Prices provided by external sources [(d)]	(84)	88	111	32	—	—	147
Prices based on model or other valuation methods	67	13	(5)	(1)	(11)	(46)	17
Total	$ (18)	$101	$106	$ 31	$ (11)	$ (46)	$ 163

(a) Mark−to−market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI.
(b) 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.
(c) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark−to−market assets and liabilities) of $540 million at December 31, 2011.
(d) Includes ComEd's net assets (liabilities) associated with the floating−to−fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within 2012	2013	2014	2015	2016	2017 and Beyond	Total Fair Value
Normal Operations, qualifying cash flow hedge contracts [(a)(c)]:							
Prices provided by external sources	$339	$246	$ 99	$ 1	$—	$ —	$ 685
Prices based on model or other valuation methods	503	191	—	—	—	—	694
Total	$842	$437	$ 99	$ 1	$—	$ —	$ 1,379
Normal Operations, other derivative contracts [(b)(c)]:							
Actively quoted prices	$ (1)	$—	$—	$—	$—	$ —	$ (1)
Prices provided by external sources	(84)	88	111	32	—	—	147
Prices based on model or other valuation methods	76	29	9	10	(1)	—	123
Total	$ (9)	$117	$120	$ 42	$ (1)	$ —	$ 269

(a) Mark−to−market gains and losses on contracts that qualify as cash flow hedges are recorded in OCI. Amounts include a $694 million gain associated with the five−year financial swap with ComEd.
(b) 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.
(c) Amounts are shown net of collateral paid to and received from counterparties (and offset against mark−to−market assets and liabilities) of $540 million at December 31, 2011.

	Maturities Within						
	2012	2013	2014	2015	2016	2017 and Beyond	Fair Value
Prices based on model or other valuation methods [(a)]	$(512)	$(207)	$(14)	$(11)	$(10)	$ (46)	$(800)

(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, Generation, ComEd and PECO)

The Registrants are exposed to credit−related losses in the event of non−performance by counterparties with whom they enter into derivative instruments. The credit exposure of derivative contracts, before collateral and netting, is represented by the fair value of contracts at the reporting date. See Note 9 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, 2011. 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 RTOs, ISOs and NYMEX and ICE commodity exchanges, which are discussed below. Additionally, the figures in the tables below do not include exposures with affiliates, including net receivables with ComEd and PECO of $70 million and $39 million, respectively. See Note 21 of the Combined Notes to Consolidated Financial Statements for further information.

Rating as of December 31, 2011	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,581	$ 351	$ 1,230	1	$ 179
Non−investment grade	5	2	3	—	—
No external ratings					
Internally rated—investment grade	63	14	49	—	—
Internally rated—non−investment grade	1	—	1	—	—
Total	$ 1,650	$ 367	$ 1,283	1	$ 179

Rating as of December 31, 2011	Maturity of Credit Risk Exposure Less than 2 Years	2−5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,127	$359	$ 95	$ 1,581
Non−investment grade	5	—	—	5
No external ratings				
Internally rated—investment grade	49	10	4	63
Internally rated—non−investment grade	1	—	—	1
Total	$ 1,182	$369	$ 99	$ 1,650

Net Credit Exposure by Type of Counterparty	As of December 31, 2011
Financial Institutions	$ 391
Investor−owned utilities, marketers and power producers	552
Energy cooperatives and municipalities	282
Other	58
Total	$ 1,283

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 will monitor nonpayment from customers and will make any necessary adjustments to the provision for uncollectible accounts. In February 2010, the ICC approved ComEd's tariffs to adjust rates annually through a rider mechanism to reflect increases or decreases in annual uncollectible accounts expense. 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, 2011. See Note 2 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. The unsecured credit used by the suppliers represents ComEd's credit exposure. As of December 31, 2011, 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, 2011.

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, 2011, PECO had no net credit exposure to 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 $14 million in parental guarantees related to these agreements. As of December 31, 2011, PECO had credit exposure of $11 million under its natural gas supply and asset management agreements with investment grade suppliers.

Collateral (Generation, ComEd and PECO)

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, the obligation to supply the collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. If Generation can reasonably claim that it is willing and financially able to perform its obligations, it may be possible to successfully argue that no collateral should be posted or that only an amount equal to two or three months of future payments should be sufficient. See Note 9 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. On March 23, 2011, Generation replaced their unsecured revolving credit facility with new a new facility with aggregate bank commitments of $5.3 billion. In addition, on

February 22, 2011, Generation satisfied all conditions precedent to the effectiveness and availability of credit under a bilateral credit facility for loans and letters of credit in the aggregate maximum amount of $300 million, which is the limit currently authorized by the board of directors of Exelon. See Note 10 – Debt and Credit Agreements for additional information.

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 against mark−to−market assets and liabilities. As of December 31, 2011, $2 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, 2010, Generation was holding $955 million of cash collateral deposits received from counterparties and Generation had sent $3 million of cash collateral to counterparties. Net cash collateral deposits received of $951 million were offset mark−to−market assets and liabilities. As of December 31, 2010, $1 million of cash collateral received was not offset against net mark−to−market assets and liabilities. See Note 18 of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

ComEd

As of December 31, 2011, ComEd held an immaterial amount 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 2 and 9 of the Combined Notes to Consolidated Financial Statements for further information.

PECO

As of December 31, 2011, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 9 of the Combined Notes to Consolidated Financial Statements for further information.

RTOs and ISOs (Generation, ComEd and PECO)

Generation, ComEd and PECO participate in all, or some, of the established, real−time energy markets that are administered by PJM, ISO−NE, New York ISO, MISO, Southwest Power Pool, Inc. and the Electric Reliability Council of Texas. 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)

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

Long−Term Leases (Exelon)

Exelon's consolidated balance sheets, as of December 31, 2011, included a $656 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 $836 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, 2011 and 2010 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, 2011, no events have occurred or circumstances have changed that would require any formal reassessment subsequent to the July 2011 review.

Interest−Rate Risk (Exelon, Generation and ComEd)

The Registrants use a combination of fixed−rate and variable−rate debt to manage interest−rate exposure. The Registrants may also use interest rate swaps when deemed appropriate to adjust exposure based upon market conditions. Additionally, the Registrants may use forward−starting interest rate swaps and treasury rate locks to lock in interest−rate levels in anticipation of future financings. These strategies are employed to achieve a lower cost of capital. At December 31, 2011, Exelon had $100 million of notional amounts of fair value hedges outstanding and Generation had $485 million of notional amounts of cash flow hedges outstanding. A hypothetical 10% increase in the interest rates associated with variable−rate debt would result in less than a $1 million decrease in Exelon's, Generation's and ComEd's pre−tax earnings for the year ended December 31, 2011. This calculation holds all other variables constant and assumes only the discussed changes in interest rates.

Equity Price Risk (Exelon and Generation)

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, 2011, 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 $342 million reduction in the fair value of the trust assets. This calculation holds all other variables constant and assumes only the discussed changes in interest rates and equity prices. See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for further discussion of equity price risk as a result of the current capital and credit market conditions.

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

Generation

General

Generation operates in three segments: Mid−Atlantic, Midwest, and South and West. The operation of all three segments consists of owned and contracted electric generating facilities, wholesale energy marketing operations and competitive retail supply operations. These segments are discussed in further detail in "ITEM 1. BUSINESS—Generation" of this Form 10−K.

Executive Overview

A discussion of items pertinent to Generation's executive overview is set forth under "ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS—Exelon—Executive Overview" of this Form 10−K.

Results of Operations

Year Ended December 31, 2011 Compared To Year Ended December 31, 2010 and Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

A discussion of Generation's results of operations for 2011 compared to 2010 and 2010 compared to 2009 is set forth under "Results of Operations—Generation" in "EXELON CORPORATION—Results of Operations" of this Form 10−K.

Liquidity and Capital Resources

Generation's business is capital intensive and requires considerable capital resources. Generation's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long−term debt, commercial paper, participation in the intercompany money pool or capital contributions from Exelon. Generation's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where Generation no longer has access to the capital markets at reasonable terms, Generation has access to credit facilities in the aggregate of $5.6 billion that Generation currently utilizes to support its commercial paper program and to issue letters of credit.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 10 of the Combined Notes to Consolidated Financial Statements of this Form 10−K for further discussion.

Capital resources are used primarily to fund Generation's capital requirements, including construction, retirement of debt, the payment of distributions to Exelon, contributions to Exelon's pension plans and investments in new and existing ventures. Future acquisitions could require external financing or borrowings or capital contributions from Exelon.

Cash Flows from Operating Activities

A discussion of items pertinent to Generation's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Cash Flows from Investing Activities

A discussion of items pertinent to Generation's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Cash Flows from Financing Activities

A discussion of items pertinent to Generation's cash flows from financing activities is set forth under "Cash Flows from Financing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Credit Matters

A discussion of credit matters pertinent to Generation is set forth under "Credit Matters" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Contractual Obligations and Off−Balance Sheet Arrangements

A discussion of Generation's contractual obligations, commercial commitments and off−balance sheet arrangements is set forth under "Contractual Obligations and Off−Balance Sheet Arrangements" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of Generation's critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Generation

Generation is exposed to market risks associated with commodity price, credit, interest rates and equity price. These risks are described above under "Quantitative and Qualitative Disclosures about Market Risk—Exelon."

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

ComEd

General

ComEd operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services to retail customers in northern Illinois, including the City of Chicago. This segment is discussed in further detail in "ITEM 1. BUSINESS—ComEd" of this Form 10−K.

Executive Overview

A discussion of items pertinent to ComEd's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10−K.

Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 and Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

A discussion of ComEd's results of operations for 2011 compared to 2010 and for 2010 compared to 2009 is set forth under "Results of Operations—ComEd" in "EXELON CORPORATION—Results of Operations" of this Form 10−K.

Liquidity and Capital Resources

ComEd's business is capital intensive and requires considerable capital resources. ComEd's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long−term debt, commercial paper or credit facility borrowings. ComEd's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. At December 31, 2011, ComEd had access to a revolving credit facility with aggregate bank commitments of $1 billion. ComEd expects to renew or replace the facility in the first half of 2012. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

See the "EXELON CORPORATION—Liquidity and Capital Resources" and Note 10 of the Combined Notes to Consolidated Financial Statements of this Form 10−K for further discussion.

Capital resources are used primarily to fund ComEd's capital requirements, including construction, retirement of debt, and contributions to Exelon's pension plans. Additionally, ComEd operates in rate−regulated environments in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to ComEd's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Cash Flows from Investing Activities

A discussion of items pertinent to ComEd's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Cash Flows from Financing Activities

A discussion of items pertinent to ComEd’s cash flows from financing activities is set forth under “Cash Flows from Financing Activities” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10−K.

Credit Matters

A discussion of credit matters pertinent to ComEd is set forth under “Credit Matters” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10−K.

Contractual Obligations and Off−Balance Sheet Arrangements

A discussion of ComEd’s contractual obligations, commercial commitments and off−balance sheet arrangements is set forth under “Contractual Obligations and Off−Balance Sheet Arrangements” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10−K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of ComEd’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

ComEd

ComEd is exposed to market risks associated with commodity price, credit and interest rates. These risks are described above under “Quantitative and Qualitative Disclosures about Market Risk— Exelon.”

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

PECO

General

PECO operates in a single business segment and its operations consist of the purchase and regulated retail sale of electricity and the provision of distribution and transmission services in southeastern Pennsylvania including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution service in Pennsylvania in the counties surrounding the City of Philadelphia. This segment is discussed in further detail in "ITEM 1. BUSINESS—PECO" of this Form 10−K.

Executive Overview

A discussion of items pertinent to PECO's executive overview is set forth under "EXELON CORPORATION—Executive Overview" of this Form 10−K.

Results of Operations

Year Ended December 31, 2011 Compared to Year Ended December 31, 2010 and Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

A discussion of PECO's results of operations for 2011 compared to 2010 and for 2010 compared to 2009 is set forth under "Results of Operations—PECO" in "EXELON CORPORATION—Results of Operations" of this Form 10−K.

Liquidity and Capital Resources

PECO's business is capital intensive and requires considerable capital resources. PECO's capital resources are primarily provided by internally generated cash flows from operations and, to the extent necessary, external financing, including the issuance of long−term debt, commercial paper or participation in the intercompany money pool. PECO's access to external financing at reasonable terms is dependent on its credit ratings and general business conditions, as well as that of the utility industry in general. If these conditions deteriorate to where PECO no longer has access to the capital markets at reasonable terms, PECO has access to a revolving credit facility. At December 31, 2011, PECO had access to a revolving credit facility with aggregate bank commitments of $600 million. See the "Credit Matters" section of "Liquidity and Capital Resources" for additional discussion.

Capital resources are used primarily to fund PECO's capital requirements, including construction, retirement of debt, the payment of dividends and contributions to Exelon's pension plans. Additionally, PECO operates in a rate−regulated environment in which the amount of new investment recovery may be limited and where such recovery takes place over an extended period of time.

Cash Flows from Operating Activities

A discussion of items pertinent to PECO's cash flows from operating activities is set forth under "Cash Flows from Operating Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Cash Flows from Investing Activities

A discussion of items pertinent to PECO's cash flows from investing activities is set forth under "Cash Flows from Investing Activities" in "EXELON CORPORATION—Liquidity and Capital Resources" of this Form 10−K.

Cash Flows from Financing Activities

A discussion of items pertinent to PECO’s cash flows from financing activities is set forth under “Cash Flows from Financing Activities” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10−K.

Credit Matters

A discussion of credit matters pertinent to PECO is set forth under “Credit Matters” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10−K.

Contractual Obligations and Off−Balance Sheet Arrangements

A discussion of PECO’s contractual obligations, commercial commitments and off−balance sheet arrangements is set forth under “Contractual Obligations and Off−Balance Sheet Arrangements” in “EXELON CORPORATION—Liquidity and Capital Resources” of this Form 10−K.

Critical Accounting Policies and Estimates

See Exelon, Generation, ComEd and PECO—Critical Accounting Policies and Estimates above for a discussion of PECO’s critical accounting policies and estimates.

New Accounting Pronouncements

See Note 1 of the Combined Notes to Consolidated Financial Statements for information regarding new accounting pronouncements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PECO

PECO is exposed to market risks associated with credit and interest rates. These risks are described above under “Quantitative and Qualitative Disclosures about Market Risk—Exelon.”

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Corporation (Exelon) is responsible for establishing and maintaining adequate internal control over financial reporting. Exelon'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 accounting principles generally accepted in the United States of America.

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, 2011. 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, 2011, Exelon's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2012

Table of Contents

Management's Report on Internal Control Over Financial Reporting

The management of Exelon Generation Company, LLC (Generation) is responsible for establishing and maintaining adequate internal control over financial reporting. Generation'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 accounting principles generally accepted in the United States of America.

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

Generation's management conducted an assessment of the effectiveness of Generation's internal control over financial reporting as of December 31, 2011. 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, Generation's management concluded that, as of December 31, 2011, Generation's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2012

Management's Report on Internal Control Over Financial Reporting

The management of Commonwealth Edison Company (ComEd) is responsible for establishing and maintaining adequate internal control over financial reporting. ComEd'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 accounting principles generally accepted in the United States of America.

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

ComEd's management conducted an assessment of the effectiveness of ComEd's internal control over financial reporting as of December 31, 2011. 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, ComEd's management concluded that, as of December 31, 2011, ComEd's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2012

Management's Report on Internal Control Over Financial Reporting

The management of PECO Energy Company (PECO) is responsible for establishing and maintaining adequate internal control over financial reporting. PECO'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 accounting principles generally accepted in the United States of America.

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

PECO's management conducted an assessment of the effectiveness of PECO's internal control over financial reporting as of December 31, 2011. 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, PECO's management concluded that, as of December 31, 2011, PECO's internal control over financial reporting was effective.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

February 9, 2012

Report of Independent Registered Public Accounting Firm

To The Shareholders and the Board of Directors of Exelon Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 15(a)(1)(i) present fairly, in all material respects, the financial position of Exelon Corporation and its subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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 accompanying index appearing under item 15(a)(1)(ii) 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, 2011, 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 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.

PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Report of Independent Registered Public Accounting Firm

To the Member and the Board of Directors of Exelon Generation Company, LLC:

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 15(a)(2)(i) present fairly, in all material respects, the financial position of Exelon Generation Company, LLC and its subsidiaries (Generation) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under item 15(a)(2)(ii) presents 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, 2011, 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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.

PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Commonwealth Edison Company:

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 15(a)(3)(i) present fairly, in all material respects, the financial position of Commonwealth Edison Company and its subsidiaries (ComEd) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under item 15(a)(3)(ii) presents 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, 2011, 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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.

PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of PECO Energy Company:

In our opinion, the consolidated financial statements listed in the accompanying index appearing under Item 15(a)(4)(i) present fairly, in all material respects, the financial position of PECO Energy Company and its subsidiaries (PECO) at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index appearing under item 15(a)(4)(ii) presents 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, 2011, 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 schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, 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.

PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions, except per share data)	For the Years Ended December 31, 2011	2010	2009
Operating revenues	$18,924	$18,644	$17,318
Operating expenses			
Purchased power	5,284	4,425	3,215
Fuel	1,844	2,010	2,066
Operating and maintenance	5,012	4,453	4,612
Operating and maintenance for regulatory required programs	184	147	63
Depreciation and amortization	1,335	2,075	1,834
Taxes other than income	785	808	778
Total operating expenses	14,444	13,918	12,568
Operating income	4,480	4,726	4,750
Other income and deductions			
Interest expense, net	(701)	(792)	(654)
Interest expense to affiliates, net	(25)	(25)	(77)
Loss in equity method investments	(1)	—	(27)
Other, net	199	312	427
Total other income and deductions	(528)	(505)	(331)
Income before income taxes	3,952	4,221	4,419
Income taxes	1,457	1,658	1,712
Net income	2,495	2,563	2,707
Other comprehensive income (loss)			
Pension and non−pension postretirement benefit plans:			
Prior service benefit reclassified to periodic costs, net of taxes of $(4), $(7) and $(6). respectively	(5)	(11)	(13)
Actuarial loss reclassified to periodic cost, net of taxes of $93, $79 and $74, respectively	136	114	93
Transition obligation reclassified to periodic cost, net of taxes of $2, $2 and $2, respectively	4	3	3
Pension and non−pension postretirement benefit plan valuation adjustment, net of taxes of $(171), $(188) and $47,respectively	(250)	(288)	86
Change in unrealized gain (loss) on cash flow hedges, net of taxes of $39, $(107) and $(2), respectively	88	(151)	(12)
Change in unrealized gain (loss) on marketable securities, net of taxes of $0, $0 and $3, respectively	—	(1)	5
Other comprehensive income (loss)	(27)	(334)	162
Comprehensive income	$ 2,468	$ 2,229	$ 2,869
Average shares of common stock outstanding:			
Basic	663	661	659
Diluted	665	663	662
Earnings per average common share:			
Basic	$ 3.76	$ 3.88	$ 4.10
Diluted	$ 3.75	$ 3.87	$ 4.09
Dividends per common share	$ 2.10	$ 2.10	$ 2.10

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income	$ 2,495	$ 2,563	$ 2,707
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel amortization	2,304	2,943	2,601
Impairment of long−lived assets	—	—	223
Deferred income taxes and amortization of investment tax credits	1,457	981	756
Net fair value changes related to derivatives	291	(88)	(95)
Net realized and unrealized losses (gains) on nuclear decommissioning trust fund investments	14	(105)	(207)
Other non−cash operating activities	782	609	652
Changes in assets and liabilities:			
Accounts receivable	57	(232)	234
Inventories	(58)	(62)	51
Accounts payable, accrued expenses and other current liabilities	(254)	472	(254)
Option premiums paid, net	(3)	(124)	(40)
Counterparty collateral (posted) received, net	(344)	(155)	196
Income taxes	492	(543)	(29)
Pension and non−pension postretirement benefit contributions	(2,360)	(959)	(588)
Other assets and liabilities	(20)	(56)	(113)
Net cash flows provided by operating activities	4,853	5,244	6,094
Cash flows from investing activities			
Capital expenditures	(4,042)	(3,326)	(3,273)
Proceeds from nuclear decommissioning trust fund sales	6,139	3,764	4,292
Investment in nuclear decommissioning trust funds	(6,332)	(3,907)	(4,531)
Acquisitions	(387)	(893)	—
Proceeds from sales of investments	6	28	41
Purchases of investments	(4)	(22)	(28)
Change in restricted cash	(3)	423	35
Other investing activities	20	39	6
Net cash flows used in investing activities	(4,603)	(3,894)	(3,458)
Cash flows from financing activities			
Changes in short−term debt	161	(155)	(56)
Issuance of long−term debt	1,199	1,398	1,987
Retirement of long−term debt	(789)	(828)	(1,773)
Retirement of long−term debt of variable interest entity	—	(806)	—
Retirement of long−term debt to financing affiliates	—	—	(709)
Dividends paid on common stock	(1,393)	(1,389)	(1,385)
Proceeds from employee stock plans	38	48	42
Other financing activities	(62)	(16)	(3)
Net cash flows used in financing activities	(846)	(1,748)	(1,897)
Increase (decrease) in cash and cash equivalents	(596)	(398)	739
Cash and cash equivalents at beginning of period	1,612	2,010	1,271
Cash and cash equivalents at end of period	$ 1,016	$ 1,612	$ 2,010

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,016	$ 1,612
Restricted cash and investments	40	30
Accounts receivable, net		
Customer ($329 and $346 gross accounts receivables pledged as collateral as of December 31, 2011 and December 31, 2010, respectively)	1,613	1,932
Other	1,000	1,196
Mark−to−market derivative assets	432	487
Inventories, net		
Fossil fuel	208	216
Materials and supplies	656	590
Deferred income taxes	97	—
Regulatory assets	69	10
Other	358	325
Total current assets	5,489	6,398
Property, plant and equipment, net	32,570	29,941
Deferred debits and other assets		
Regulatory assets	4,839	4,140
Nuclear decommissioning trust funds	6,507	6,408
Investments	751	717
Investments in affiliates	15	15
Goodwill	2,625	2,625
Mark−to−market derivative assets	650	409
Pledged assets for Zion Station decommissioning	734	824
Other	912	763
Total deferred debits and other assets	17,033	15,901
Total assets	$55,092	$52,240

See the Combined Notes to Consolidated Financial Statements

Exelon Corporation and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short−term borrowings	$ 163	$ —
Short−term notes payable—accounts receivable agreement	225	225
Long−term debt due within one year	828	599
Accounts payable	1,444	1,373
Mark−to−market derivative liabilities	112	38
Accrued expenses	1,255	1,040
Deferred income taxes	—	85
Regulatory liabilities	53	44
Dividends payable	349	1
Other	560	835
Total current liabilities	4,989	4,240
Long−term debt	11,799	11,614
Long−term debt to other financing trusts	390	390
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	8,351	6,621
Asset retirement obligations	3,884	3,494
Pension obligations	2,194	3,658
Non−pension postretirement benefit obligations	2,263	2,218
Spent nuclear fuel obligation	1,019	1,018
Regulatory liabilities	3,771	3,555
Mark−to−market derivative liabilities	126	21
Payable for Zion Station decommissioning	563	659
Other	1,268	1,102
Total deferred credits and other liabilities	23,439	22,346
Total liabilities	40,617	38,590
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 663 and 662 shares outstanding at December 31, 2011 and 2010, respectively)	9,107	9,006
Treasury stock, at cost (35 shares held at December 31, 2011 and 2010, respectively)	(2,327)	(2,327)
Retained earnings	10,055	9,304
Accumulated other comprehensive loss, net	(2,450)	(2,423)
Total shareholders' equity	14,385	13,560
Noncontrolling interest	3	3
Total equity	14,388	13,563
Total liabilities and shareholders' equity	$55,092	$52,240

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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	Total Shareholders' Equity
Balance, December 31, 2008	692,953	$ 8,816	$ (2,338)	$ 6,820	$ (2,251)	$ —	$ 11,047
Net income	—	—	—	2,707	—	—	2,707
Long−term incentive plan activity	1,088	85	10	(5)	—	—	90
Employee stock purchase plan issuances	524	22	—	—	—	—	22
Common stock dividends	—	—	—	(1,388)	—	—	(1,388)
Other comprehensive income, net of income taxes of $119	—	—	—	—	162	—	162
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 loss, 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	—	—	2,495
Long−term incentive plan activity	861	76	—	—	—	—	76
Employee stock purchase plan issuances	662	25	—	—	—	—	25
Common stock dividends	—	—	—	(1,744)	—	—	(1,744)
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

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	For the Years Ended December 31, 2011	2010	2009
Operating revenues			
Operating revenues	$ 9,147	$ 6,923	$6,231
Operating revenues from affiliates	1,161	3,102	3,472
Total operating revenues	10,308	10,025	9,703
Operating expenses			
Purchased power	1,922	1,853	1,338
Fuel	1,528	1,610	1,594
Operating and maintenance	2,827	2,521	2,632
Operating and maintenance from affiliates	321	291	306
Depreciation and amortization	570	474	333
Taxes other than income	264	230	205
Total operating expenses	7,432	6,979	6,408
Operating income	2,876	3,046	3,295
Other income and deductions			
Interest expense	(170)	(153)	(113)
Loss in equity method investments	(1)	—	(3)
Other, net	122	257	376
Total other income and deductions	(49)	104	260
Income before income taxes	2,827	3,150	3,555
Income taxes	1,056	1,178	1,433
Net income	1,771	1,972	2,122
Other comprehensive income (loss)			
Change in unrealized gain (loss) on cash flow hedges, net of income taxes of $(64), $(102) and $199, respectively	(98)	(144)	302
Other comprehensive income (loss)	(98)	(144)	302
Comprehensive income	$ 1,673	$ 1,828	$2,424

See the Combined Notes to Consolidated Financial Statements

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income	$ 1,771	$ 1,972	$ 2,122
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion, including nuclear fuel amortization	1,539	1,341	1,098
Impairment of long−lived assets	—	—	223
Deferred income taxes and amortization of investment tax credits	551	741	671
Net fair value changes related to derivatives	291	(88)	(95)
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	14	(105)	(207)
Other non−cash operating activities	421	182	104
Changes in assets and liabilities:			
Accounts receivable	(122)	—	172
Receivables from and payables to affiliates, net	208	(5)	(54)
Inventories	(47)	(70)	(29)
Accounts payable, accrued expenses and other current liabilities	34	(18)	(43)
Option premiums paid, net	(3)	(124)	(40)
Counterparty collateral (posted) received, net	(410)	(1)	195
Income taxes	193	(303)	79
Pension and non−pension postretirement benefit contributions	(1,070)	(445)	(265)
Other assets and liabilities	(57)	(45)	(1)
Net cash flows provided by operating activities	3,313	3,032	3,930
Cash flows from investing activities			
Capital expenditures	(2,491)	(1,883)	(1,977)
Proceeds from nuclear decommissioning trust fund sales	6,139	3,764	4,292
Investment in nuclear decommissioning trust funds	(6,332)	(3,907)	(4,531)
Acquisitions	(387)	(893)	—
Change in restricted cash	—	4	17
Other investing activities	(6)	19	(21)
Net cash flows used in investing activities	(3,077)	(2,896)	(2,220)
Cash flows from financing activities			
Issuance of long−term debt	—	898	1,546
Retirement of long−term debt	(2)	(215)	(1,065)
Distribution to member	(172)	(1,508)	(2,276)
Contribution from member	30	62	57
Other financing activities	(52)	(16)	(8)
Net cash flows used in financing activities	(196)	(779)	(1,746)
Increase (decrease) in cash and cash equivalents	40	(643)	(36)
Cash and cash equivalents at beginning of period	456	1,099	1,135
Cash and cash equivalents at end of period	$ 496	$ 456	$ 1,099

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 496	$ 456
Restricted cash and cash equivalents	5	1
Accounts receivable, net		
Customer	578	469
Other	257	161
Mark−to−market derivative assets	432	487
Mark−to−market derivative assets with affiliate	503	455
Receivables from affiliates	109	306
Inventories, net		
Fossil fuel	120	129
Materials and supplies	556	500
Other	148	123
Total current assets	3,204	3,087
Property, plant and equipment, net	13,475	11,662
Deferred debits and other assets		
Nuclear decommissioning trust funds	6,507	6,408
Investments	41	35
Receivable from affiliate	1	1
Mark−to−market derivative assets	635	391
Mark−to−market derivative assets with affiliate	191	525
Prepaid pension asset	2,068	1,236
Pledged assets for Zion Station decommissioning	734	824
Other	577	365
Total deferred debits and other assets	10,754	9,785
Total assets	$27,433	$24,534

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities		
Short−term borrowings	$ 2	$ —
Long−term debt due within one year	3	3
Accounts payable	753	749
Accrued expenses	779	391
Payables to affiliates	58	47
Deferred income taxes	244	427
Mark−to−market derivative liabilities	103	34
Other	202	192
Total current liabilities	2,144	1,843
Long−term debt	3,674	3,676
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,966	3,318
Asset retirement obligations	3,767	3,357
Non−pension postretirement benefit obligations	703	692
Spent nuclear fuel obligation	1,019	1,018
Payables to affiliates	2,222	2,267
Mark−to−market derivative liabilities	29	21
Payable for Zion Station decommissioning	563	659
Other	638	506
Total deferred credits and other liabilities	12,907	11,838
Total liabilities	18,725	17,357
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	3,556	3,526
Undistributed earnings	4,232	2,633
Accumulated other comprehensive income, net	915	1,013
Total member's equity	8,703	7,172
Noncontrolling interest	5	5
Total equity	8,708	7,177
Total liabilities and equity	$27,433	$24,534

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Consolidated Statements of Changes in Member's Equity

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total Equity
Balance, December 31, 2008	$ 3,407	$ 2,323	$ 835	$ 1	$ 6,566
Net Income	—	2,122	—	—	2,122
Distribution to member	—	(2,276)	—	—	(2,276)
Allocation of tax benefit from member	57	—	—	—	57
Transfer of AmerGen pension and non−pension postretirement benefit plans to Exelon, net of income taxes of $17	—	—	20	—	20
Other comprehensive income, net of income taxes of $199	—	—	302	—	302
Noncontrolling interest in income of consolidated entity	—	—	—	1	1
Balance, December 31, 2009	$ 3,464	$ 2,169	$ 1,157	$ 2	$ 6,792
Net Income	—	1,972	—	—	1,972
Distribution to member	—	(1,508)	—	—	(1,508)
Allocation of tax benefit from member	62	—	—	—	62
Acquisition of Exelon Wind	—	—	—	3	3
Other comprehensive loss, net of income taxes of $(102)	—	—	(144)	—	(144)
Balance, December 31, 2010	$ 3,526	$ 2,633	$ 1,013	$ 5	$ 7,177
Net income	—	1,771	—	—	1,771
Distribution to member	—	(172)	—	—	(172)
Allocation of tax benefit from member	30	—	—	—	30
Other comprehensive loss, net of income taxes of $(64)	—	—	(98)	—	(98)
Balance, December 31, 2011	$ 3,556	$ 4,232	$ 915	$ 5	$ 8,708

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(in millions)	For the Years Ended December 31, 2011	2010	2009
Operating revenues			
Operating revenues	$6,054	$6,202	$5,772
Operating revenues from affiliates	2	2	2
Total operating revenues	6,056	6,204	5,774
Operating expenses			
Purchased power	2,382	2,297	1,609
Purchased power from affiliate	653	1,010	1,456
Operating and maintenance	928	823	863
Operating and maintenance from affiliate	158	152	165
Operating and maintenance for regulatory required programs	115	94	63
Depreciation and amortization	542	516	494
Taxes other than income	296	256	281
Total operating expenses	5,074	5,148	4,931
Operating income	982	1,056	843
Other income and deductions			
Interest expense	(330)	(373)	(306)
Interest expense to affiliates, net	(15)	(13)	(13)
Other, net	29	24	79
Total other income and deductions	(316)	(362)	(240)
Income before income taxes	666	694	603
Income taxes	250	357	229
Net income	416	337	374
Other comprehensive income			
Change in unrealized gain (loss) on marketable securities, net of income taxes of $0, $0 and $3, respectively	—	(1)	5
Other comprehensive income (loss)	—	(1)	5
Comprehensive income	$ 416	$ 336	$ 379

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income	$ 416	$ 337	$ 374
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	542	517	495
Deferred income taxes and amortization of investment tax credits	700	582	265
Other non−cash operating activities	196	238	309
Changes in assets and liabilities:			
Accounts receivable	5	(46)	29
Receivables from and payables to affiliates, net	(287)	(55)	(27)
Inventories	(9)	(1)	4
Accounts payable, accrued expenses and other current liabilities	(84)	342	(48)
Counterparty collateral received (posted), net	66	(154)	1
Income taxes	223	(233)	(105)
Pension and non−pension postretirement benefit contributions	(977)	(317)	(214)
Other assets and liabilities	45	(133)	(63)
Net cash flows provided by operating activities	836	1,077	1,020
Cash flows from investing activities			
Capital expenditures	(1,028)	(962)	(854)
Proceeds from sales of investments	6	28	41
Purchases of investments	(4)	(22)	(28)
Other investing activities	19	17	20
Net cash flows used in investing activities	(1,007)	(939)	(821)
Cash flows from financing activities			
Changes in short−term debt	—	(155)	95
Issuance of long−term debt	1,199	500	191
Retirement of long−term debt	(537)	(213)	(208)
Contributions from parent	—	2	8
Dividends paid on common stock	(300)	(310)	(240)
Other financing activities	(7)	(3)	(1)
Net cash flows provided by (used in) financing activities	355	(179)	(155)
Increase (decrease) in cash and cash equivalents	184	(41)	44
Cash and cash equivalents at beginning of period	50	91	47
Cash and cash equivalents at end of period	$ 234	$ 50	$ 91

See the Combined Notes to Consolidated Financial Statements

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 234	$ 50
Restricted cash	3	—
Accounts receivable, net		
Customer	655	768
Other	385	525
Inventories, net	81	72
Deferred income taxes	76	115
Counterparty collateral deposited	90	153
Regulatory assets	560	456
Other	22	12
Total current assets	2,106	2,151
Property, plant and equipment, net	13,121	12,578
Deferred debits and other assets		
Regulatory assets	796	947
Investments	21	23
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivable from affiliates	1,860	1,895
Mark−to−market derivative assets	—	4
Prepaid pension asset	1,803	1,039
Other	315	384
Total deferred debits and other assets	7,426	6,923
Total assets	$22,653	$21,652

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Long−term debt due within one year	$ 450	$ 347
Accounts payable	325	332
Accrued expenses	318	366
Payables to affiliates	111	398
Customer deposits	136	130
Regulatory liabilities	12	19
Mark−to−market derivative liability	9	—
Mark−to−market derivative liability with affiliate	503	450
Other	82	92
Total current liabilities	1,946	2,134
Long−term debt	5,215	4,654
Long−term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,008	3,308
Asset retirement obligations	89	105
Non−pension postretirement benefits obligations	271	271
Regulatory liabilities	3,167	3,137
Mark−to−market derivative liability	97	—
Mark−to−market derivative liability with affiliate	191	525
Other	426	402
Total deferred credits and other liabilities	8,249	7,748
Total liabilities	15,616	14,742
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid−in capital	5,003	4,992
Retained earnings	447	331
Accumulated other comprehensive loss, net	(1)	(1)
Total shareholders' equity	7,037	6,910
Total liabilities and shareholders' equity	$22,653	$21,652

See the Combined Notes to Consolidated Financial Statements

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Consolidated Statements of Changes in Shareholders' Equity

(In millions)	Common Stock	Other Paid−In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity
Balance, December 31, 2008	$ 1,588	$ 4,982	$ (1,639)	$ 1,809	$ (5)	$ 6,735
Net income	—	—	374	—	—	374
Common stock dividends	—	—	—	(240)	—	(240)
Allocation of tax benefit from parent	—	8	—	—	—	8
Appropriation of retained earnings for future dividends	—	—	(374)	374	—	—
Other comprehensive income, net of income taxes of $3	—	—	—	—	5	5
Balance, December 31, 2009	$ 1,588	$ 4,990	$ (1,639)	$ 1,943	$ —	$ 6,882
Net income	—	—	337	—	—	337
Common stock dividends	—	—	—	(310)	—	(310)
Allocation of tax benefit from parent	—	2	—	—	—	2
Appropriation of retained earnings for future dividends	—	—	(337)	337	—	—
Other comprehensive loss, net of income taxes of $0	—	—	—	—	(1)	(1)
Balance, December 31, 2010	$ 1,588	$ 4,992	$ (1,639)	$ 1,970	$ (1)	$ 6,910
Net income	—	—	416	—	—	416
Common stock dividends	—	—	—	(300)	—	(300)
Allocation of tax benefit from parent	—	11	—	—	—	11
Appropriation of retained earnings for future dividends	—	—	(416)	416	—	—
Other comprehensive income net of income taxes of $0	—	—	—	—	—	—
Balance, December 31, 2011	$ 1,588	$ 5,003	$ (1,639)	$ 2,086	$ (1)	$ 7,037

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Operations and Comprehensive Income

(In millions)	2011	2010	2009
	For the Years Ended December 31,		
Operating revenues			
Operating revenues	$3,715	$5,514	$5,302
Operating revenues from affiliates	5	5	9
Total operating revenues	3,720	5,519	5,311
Operating expenses			
Purchased power	1,052	276	269
Purchased power from affiliate	495	2,085	2,005
Fuel	317	401	472
Operating and maintenance	629	591	545
Operating and maintenance from affiliate	96	89	95
Operating and maintenance for regulatory required programs	69	53	—
Depreciation and amortization	202	1,060	952
Taxes other than income	205	303	276
Total operating expenses	3,065	4,858	4,614
Operating income	655	661	697
Other income and deductions			
Interest expense	(122)	(181)	(124)
Interest expense to affiliates, net	(12)	(12)	(63)
Loss in equity method investments	—	—	(24)
Other, net	14	8	13
Total other income and deductions	(120)	(185)	(198)
Income before income taxes	535	476	499
Income taxes	146	152	146
Net income	389	324	353
Preferred security dividends	4	4	4
Net income on common stock	385	320	349
Comprehensive income, net of income taxes			
Net income	389	324	353
Other comprehensive loss			
Amortization of realized gain on settled cash flow swaps, net of income taxes of $0, $(1) and $(1), respectively	—	(1)	(1)
Other comprehensive loss	—	(1)	(1)
Comprehensive income	$ 389	$ 323	$ 352

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2011	2010	2009
Cash flows from operating activities			
Net income	$ 389	$ 324	$ 353
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation, amortization and accretion	202	1,060	952
Deferred income taxes and amortization of investment tax credits	253	(400)	(210)
Other non−cash operating activities	100	108	141
Changes in assets and liabilities:			
Accounts receivable	225	(212)	36
Receivables from and payables to affiliates, net	(217)	86	45
Inventories	—	9	76
Accounts payable, accrued expenses and other current liabilities	34	85	(123)
Income taxes	(45)	118	(18)
Pension and non−pension postretirement benefit contributions	(137)	(106)	(52)
Other assets and liabilities	14	78	(34)
Net cash flows provided by operating activities	818	1,150	1,166
Cash flows from investing activities			
Capital expenditures	(481)	(545)	(388)
Changes in Exelon intercompany money pool contributions	(82)	—	—
Change in restricted cash	(2)	414	1
Other investing activities	8	11	10
Net cash flows used in investing activities	(557)	(120)	(377)
Cash flows from financing activities			
Changes in short−term debt	—	—	(95)
Issuance of long−term debt	—	—	250
Retirement of long−term debt	(250)	—	—
Retirement of long−term debt of variable interest entity	—	(806)	—
Retirement of long−term debt to PECO Energy Transition Trust	—	—	(709)
Contributions from parent	18	43	27
Dividends paid on common stock	(348)	(224)	(312)
Dividends paid on preferred securities	(4)	(4)	(4)
Repayment of receivable from parent	—	180	320
Other financing activities	(5)	—	(2)
Net cash flows used in financing activities	(589)	(811)	(525)
Increase (decrease) in cash and cash equivalents	(328)	219	264
Cash and cash equivalents at beginning of period	522	303	39
Cash and cash equivalents at end of period	$ 194	$ 522	$ 303

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 194	$ 522
Restricted cash and cash equivalents	2	—
Accounts receivable, net		
Customer ($329 and $346 gross accounts receivable pledged as collateral as of December 31, 2011 and 2010, respectively)	380	695
Other	376	277
Inventories, net		
Fossil fuel	87	87
Materials and supplies	18	18
Deferred income taxes	25	41
Receivable from Exelon intercompany money pool	82	—
Regulatory assets	12	9
Other	40	21
Total current assets	1,216	1,670
Property, plant and equipment, net	5,874	5,620
Deferred debits and other assets		
Regulatory assets	1,243	968
Investments	22	20
Investments in affiliates	8	8
Receivable from affiliates	365	375
Prepaid pension asset	382	281
Other	46	43
Total deferred debits and other assets	2,066	1,695
Total assets	$9,156	$8,985

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO Energy Company and Subsidiary Companies
Consolidated Balance Sheets

(In millions)	December 31, 2011	2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short−term notes payable—accounts receivable agreement	$ 225	$ 225
Long−term debt due within one year	375	250
Accounts payable	262	201
Accrued expenses	83	95
Payables to affiliates	62	275
Customer deposits	53	65
Regulatory liabilities	41	25
Mark−to−market derivative liabilities	—	4
Mark−to−market derivative liabilities with affiliate	—	5
Other	25	18
Total current liabilities	1,126	1,163
Long−term debt	1,597	1,972
Long−term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,170	1,823
Asset retirement obligations	28	32
Non−pension postretirement benefits obligations	288	292
Regulatory liabilities	604	418
Other	134	131
Total deferred credits and other liabilities	3,224	2,696
Total liabilities	6,131	6,015
Commitments and contingencies		
Preferred securities	87	87
Shareholders' equity		
Common stock	2,379	2,361
Retained earnings	559	522
Total shareholders' equity	2,938	2,883
Total liabilities and shareholders' equity	$9,156	$8,985

See the Combined Notes to Consolidated Financial Statements

PECO Energy Company and Subsidiary Companies
Consolidated Statements of Changes in Stockholders' Equity

(In millions)	Common Stock	Receivable from Parent	Retained Earnings	Accumulated Other Comprehensive Income	Total Shareholders' Equity
Balance, December 31, 2008	$ 2,291	$ (500)	$ 389	$ 2	$ 2,182
Net Income	—	—	353	—	353
Common stock dividends	—	—	(312)	—	(312)
Preferred security dividends	—	—	(4)	—	(4)
Repayment of receivable from parent	—	320	—	—	320
Allocation of tax benefit from parent	27	—	—	—	27
Other comprehensive loss, net of income taxes of $(1)	—	—	—	(1)	(1)
Balance, December 31, 2009	$ 2,318	$ (180)	$ 426	$ 1	$ 2,565
Net Income	—	—	324	—	324
Common stock dividends	—	—	(224)	—	(224)
Preferred security dividends	—	—	(4)	—	(4)
Repayment of receivable from parent	—	180	—	—	180
Allocation of tax benefit from parent	43	—	—	—	43
Other comprehensive loss, net of income taxes of $(1)	—	—	—	(1)	(1)
Balance, December 31, 2010	$ 2,361	$ —	$ 522	$ —	$ 2,883
Net Income	—	—	389	—	389
Common stock dividends	—	—	(348)	—	(348)
Preferred security dividends	—	—	(4)	—	(4)
Allocation of tax benefit from parent	18	—	—	—	18
Balance, December 31, 2011	$ 2,379	$ —	$ 559	$ —	$ 2,938

See the Combined Notes to Consolidated Financial Statements

Combined Notes to Consolidated Financial Statements
(Dollars in millions, except per share data unless otherwise noted)

1. Significant Accounting Policies (Exelon, Generation, ComEd and PECO)

Description of Business (Exelon, Generation, ComEd and PECO)

Exelon is a utility services holding company engaged, through its subsidiaries, in the generation and energy delivery businesses discussed below. The generation business consists of the electric generating facilities, the wholesale energy marketing operations and competitive retail supply operations of Generation. The energy delivery businesses include the purchase and regulated retail sale of electricity and the provision of transmission and distribution services by ComEd in northern Illinois, including the City of Chicago, and by PECO in southeastern Pennsylvania, including the City of Philadelphia, and the purchase and regulated retail sale of natural gas and the provision of distribution services by PECO in the Pennsylvania counties surrounding the City of Philadelphia.

Basis of Presentation (Exelon, Generation, ComEd and PECO)

This is a combined annual report of Exelon, Generation, ComEd and PECO. The Notes to the Consolidated Financial Statements apply to Exelon, Generation, ComEd and PECO as indicated parenthetically next to each corresponding disclosure.

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%, and PECO, of which Exelon owns 100% of the common stock but none of PECO's preferred securities. Exelon has reflected the third−party interests in ComEd, which totaled less than $1 million at December 31, 2011 and December 31, 2010, as equity and PECO's preferred securities as preferred securities of subsidiary in its consolidated financial statements.

Generation owns 100% of all of its significant consolidated subsidiaries, either directly or indirectly, except for 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%, and which is included in noncontrolling interest on Exelon's and Generation's Consolidated Balance Sheets.

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 12.5% is indirectly owned by Exelon, which is eliminated in Exelon's consolidated financial statements. 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, 2011, as equity.

Exelon's consolidated financial statements include the accounts of entities in which Exelon has a controlling financial interest, other than certain financing trusts of ComEd and PECO, and Generation's and PECO's proportionate interests in jointly owned electric utility property, after the elimination of intercompany transactions. A controlling financial interest is evidenced by either a voting interest greater than 50% or the results of a model that identifies Exelon or one of its subsidiaries as the primary beneficiary of a VIE. Investments and joint ventures in which Exelon does not have a controlling financial interest and certain financing trusts of ComEd and PECO are accounted for under the equity or cost method of accounting.

Each of Generation's, ComEd's and PECO's consolidated financial statements includes the accounts of their subsidiaries. All intercompany transactions have been eliminated.

Use of Estimates (Exelon, Generation, ComEd and PECO)

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. 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, fixed asset depreciation, environmental costs, taxes and unbilled energy revenues. Actual results could differ from those estimates.

Reclassifications (Exelon, ComEd and PECO)

Certain prior year amounts in Exelon's, Generation's, ComEd's and PECO's 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 of the Registrants.

Accounting for the Effects of Regulation (Exelon, ComEd and PECO)

Exelon, ComEd and PECO apply the authoritative guidance for accounting for certain types of regulations, which requires ComEd and PECO 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 and PECO account for their regulated operations in accordance with regulatory and legislative guidance from the regulatory authorities having jurisdiction, principally the ICC and the PAPUC, 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 and PECO 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 or PECO's business was no longer able to meet the criteria discussed above, Exelon, ComEd and PECO 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 2—Regulatory Matters for additional information.

Variable Interest Entities (Exelon, Generation, ComEd and PECO)

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 who do not receive expected losses or returns significant to the VIE. Companies are required to consolidate a VIE if they are its primary beneficiary.

Generation

Generation's wholesale 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 18—Commitments and Contingencies. Generation has evaluated these contracts and its membership with NEIL and determined that either it has no variable interest in an entity or, where Generation does have a variable interest in an entity, it is not the primary beneficiary and, therefore, consolidation is not required.

For contracts where Generation has a variable interest, 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, under the contracts Generation receives less than the majority of the output of the remaining expected useful life of the facilities, and Generation does not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 18—Commitments and Contingencies. Upon consideration of these factors, Generation does not consider itself to be the primary beneficiary of these VIEs and, accordingly, has determined that consolidation is not required.

Generation has historically aggregated its contracts with VIEs into two categories, energy commitments and fuel purchase obligations, based on similar risk characteristics and significance to Generation. As of the balance sheet date, the carrying amount of assets and liabilities in Generation's Consolidated Balance Sheets that relate to its involvement with these VIEs are predominately related to working capital accounts and generally represent the amounts owed by Generation for the deliveries associated with the current billing cycles under the contracts. Further, Generation has not provided or guaranteed any debt or equity support, or any liquidity arrangements, performance guarantees or other commitments associated with these contracts, so there is no significant potential exposure to loss as a result of its involvement with the VIEs.

Several of Generation's long−term PPAs have been determined to be operating leases that have no residual value guarantees, bargain purchase options or other provisions that would cause these operating leases to be variable interests.

On December 9, 2010, Generation completed the acquisition of all of the equity interests of John Deere Renewables, LLC (now known as Exelon Wind), discussed further in Note 3—Acquisition. Generation evaluated the significant agreements and ownership structures and risks of each of the wind projects and underlying entities acquired, and determined that the entities are VIEs for which Generation is the primary beneficiary and consolidation is required. Each project was designed to develop, construct and operate a wind generation facility. Generation owns 100% of most projects acquired; however, 12 of the projects have noncontrolling equity interests held by others (which range between 1% and 6%). Of the 12 projects, Generation's economic interests in nine of the projects are significantly greater than its stated contractual governance rights. However, Generation has determined that its significant economic interests in the projects include the power to direct the activities most significant to the projects. The primary factors considered in determining that Generation is the primary beneficiary were that Generation has the power to direct the operations and maintenance of the wind facilities, which is considered the activity that most significantly affects the economic performance of the projects, and the obligation to absorb losses and right to receive benefits that are significant to the projects. The ownership agreements with the noncontrolling interests state that Generation is to provide financial support to the projects in proportion to its economic interests in the projects (which range between 99% and 94%). No additional support to these projects beyond what was contractually required has been provided during 2011. As of December 31, 2011, the carrying amount of the assets and liabilities that are consolidated as a result of Generation being the primary beneficiary of these entities primarily relate to the wind generating assets, PPA intangible assets and working capital amounts.

Generation has entered into an asset sale agreement with EnergySolutions, Inc. and certain of its subsidiaries, including ZionSolutions, LLC (ZionSolutions), which is further discussed in Note 12—Asset Retirement Obligations. Generation has evaluated this agreement and determined that it has a variable interest in ZionSolutions but is not the primary beneficiary. As a result, Generation has concluded that consolidation is not required.

ComEd and PECO

ComEd's retail operations include the purchase of electricity and RECs through procurement contracts of varying durations. PECO's retail operations include the purchase of electricity, AECs and natural gas through procurement contracts of varying durations. These contracts are discussed in further detail in Note 2 – Regulatory Matters and Note 18—Commitments and Contingencies. ComEd and PECO have evaluated these contracts and determined that either there is no variable interest, or where either ComEd or PECO does have a variable interest in a VIE as described below, ComEd or PECO is not the primary beneficiary and, therefore, consolidation is not required.

For contracts where ComEd or PECO has a variable interest, consideration has been 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 and PECO do not have control over the operation and maintenance of the entities considered VIEs and they do not bear operational risk related to the associated activities. Furthermore, ComEd and PECO have no debt or equity investments in the VIEs and do not provide any other financial support through liquidity arrangements, guarantees or other commitments other than purchase commitments described in Note 18—Commitments and Contingencies. Accordingly, neither ComEd nor PECO considers itself to be the primary beneficiary of these VIEs.

As of the balance sheet date, the carrying amounts of assets and liabilities in ComEd's and PECO's Consolidated Balance Sheets that relate to their involvement with these VIEs were predominately related to working capital accounts and generally represented the amounts owed by ComEd and PECO for the purchases associated with the current billing cycles under the contracts.

The financing trust of ComEd, ComEd Financing III, and the financing trusts of PECO, PECO Trust III and PECO Trust IV, are not consolidated in Exelon's, ComEd's or PECO's financial statements. These financing trusts were created to issue mandatorily redeemable trust preferred securities. ComEd and PECO have concluded that they do not have a variable interest in ComEd Financing III, PECO Trust III or PECO Trust IV as each Registrant financed its equity interest in the financing trusts through the issuance of subordinated debt and, therefore, has no equity at risk. ComEd and PECO, as the sponsors of the financing trusts, are obligated to pay the operating expenses of the trusts.

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. PECO made an initial capital contribution of $25 million to PETT. ITP represented the irrevocable right of PECO to collect intangible transition charges (ITC). ITC consisted of the portion of CTCs that were sold by PECO to PETT and securitized through the various issuances of PETT's transition bonds from 1999 through 2001 as authorized by the PAPUC. ITC provided PETT with an asset sufficient to recover the aggregate principal amount of the transition bonds issued, plus amounts sufficient to provide for the credit enhancement, interest payments, servicing fees and other expenses relating to the transition bonds. PETT's assets were restricted for the sole purpose of satisfying PETT's obligation to its transition bondholders and payment of various administrative fees. PECO did not provide ongoing financial support to PETT or guarantee PETT's performance, and the transition bondholders did not have recourse to PECO. PECO had continuing involvement in PETT in its role as the servicer of the ITC collections, for which PECO received a fee.

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 previously issued authoritative guidance, PETT was deconsolidated in accordance with a prescribed quantitative approach, based on expected losses, for determining the primary beneficiary. Under the new 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.

Revenues (Exelon, Generation, ComEd and PECO)

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. See Notes 2—Regulatory Matters and 4—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.

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, unless hedge accounting is applied. Premiums received and paid on option contracts are recognized as revenue or expense over the terms of the contracts. If the derivatives meet hedging criteria, changes in fair value are recorded in OCI. ComEd has not elected hedge accounting for its financial swap contract with Generation. Since ComEd is entitled to full recovery of the costs of the financial swap contract 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.

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.

Income Taxes (Exelon, Generation, ComEd and PECO)

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 previously utilized for income tax purposes have been deferred on the Registrants' Consolidated Balance Sheets and are recognized in book income over the life of the related property. In accordance with applicable authoritative guidance, the Registrants account for uncertain income tax positions using a benefit recognition model with a two−step approach; a more−likely−than−not recognition criterion and a measurement approach that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more likely than not that the benefit of the tax position will be sustained on its technical merits, no benefit is recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. The Registrants recognize accrued interest related to unrecognized tax benefits in interest expense or in other income and deductions (interest income) on their 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 11—Income Taxes for further information.

Taxes Directly Imposed on Revenue−Producing Transactions (Exelon, Generation, ComEd and PECO)

Exelon, Generation, ComEd and PECO present any tax assessed by a governmental authority that 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 19—Supplemental Financial Information for Generation's, ComEd's and PECO's utility taxes that are presented on a gross basis.

Cash and Cash Equivalents (Exelon, Generation, ComEd and PECO)

The Registrants consider investments purchased with an original maturity of three months or less to be cash equivalents.

Restricted Cash and Investments (Exelon, Generation, ComEd and PECO)

Restricted cash and investments represent restricted funds to satisfy designated current liabilities. As of December 31, 2011 and 2010, Exelon Corporate's restricted cash and investments primarily represented restricted funds for payment of medical, dental, vision and long−term disability benefits. As of December 31, 2011 and 2010, Generation's restricted cash and investments represented funds in escrow related to the acquisition of Shooting Star Wind Project, LLC, and for payment of certain environmental liabilities. As of December 31, 2010, Generation's restricted cash and investments represented funds for payment of certain environmental liabilities. As of December 31, 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.

Restricted cash and investments not available to satisfy current liabilities are classified as noncurrent assets. As of December 31, 2011 and 2010, Exelon and Generation's NDT funds, which are designated to satisfy future decommissioning obligations, were classified as noncurrent assets. As of December 31, 2011 and 2010, ComEd had short−term investments in Rabbi trusts classified as noncurrent assets.

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

The allowance for uncollectible accounts reflects the Registrants' best estimates of losses on the accounts receivable balances. For Generation, the allowance is based on accounts receivable agings, historical experience and other currently available information. ComEd and PECO estimate the allowance for uncollectible accounts on customer receivables by applying internally developed loss rates 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. ComEd and PECO 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 and PECO customer accounts are written off consistent with approved regulatory requirements. ComEd's and PECO's provisions for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions as well as changes in ICC and PAPUC regulations, respectively. See Note 2—Regulatory Matters for additional information regarding the regulatory recovery of uncollectible accounts receivable at ComEd.

Inventories (Exelon, Generation, ComEd and PECO)

Inventory is recorded at the lower of 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, coal 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 and other deferred debits 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 (Exelon, Generation, ComEd and PECO)

All marketable securities are reported at fair value. Marketable securities held in the NDT funds are classified as trading securities and all securities that are not held by the NDT funds 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 and the 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. 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 12—Asset Retirement Obligations for information regarding marketable securities held by NDT funds and Note 19—Supplemental Financial Information for additional information regarding ComEd's and PECO's regulatory assets and liabilities.

Property, Plant and Equipment (Exelon, Generation, ComEd and PECO)

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 and PECO. The cost of repairs and maintenance, including planned major maintenance activities and minor replacements of property, is charged to maintenance expense as incurred.

Third parties reimburse ComEd and PECO for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs (CIAC) are netted against the project costs. DOE SGIG funds reimbursed to PECO by the DOE 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 when incurred to gross plant 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 expense as incurred.

For ComEd and PECO, upon retirement, the cost of property, net of salvage, is charged to accumulated depreciation in accordance with the composite method of depreciation. ComEd's depreciation expense includes the estimated cost of dismantling and removing plant from service upon retirement, which is consistent with ComEd's regulatory recovery method. ComEd's actual incurred removal costs are applied against the 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.

See Note 5—Property, Plant and Equipment, Note 6—Jointly Owned Electric Utility Plant and Note 19—Supplemental Financial Information for additional information regarding property, plant and equipment.

Nuclear Fuel (Exelon and Generation)

The cost of nuclear fuel is capitalized 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 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 (Exelon and Generation)

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

New Site Development Costs (Exelon and Generation)

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 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, 2011 and 2010, Exelon and Generation's capitalized development costs totaled approximately $376 million and $20 million, respectively, which are included in Property, Plant and Equipment on Exelon and Generation's Consolidated Balance Sheets. These costs primarily include land rights and other third−party costs directly associated with the development of certain Exelon Wind projects. Approximately $2 million, $6 million and $23 million of costs were expensed by Exelon and Generation for the years ended December 31, 2011, 2010 and 2009, respectively. The 2011 and 2010 costs primarily related to the possible development of new renewable energy projects while the 2009 costs primarily related to the possible construction of a new nuclear plant in Texas.

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

Capitalized Software Costs (Exelon, Generation, ComEd and PECO)

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	Exelon	Generation	ComEd	PECO
December 31, 2011	$ 280	$ 82	$ 120	$ 67
December 31, 2010	312	92	143	64

Amortization of capitalized software costs	Exelon	Generation	ComEd	PECO
2011	$ 122	$ 41	$ 50	$ 25
2010	104	33	41	19
2009	105	24	29	15

Depreciation and Amortization (Exelon, Generation, ComEd and PECO)

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 depreciation includes a provision for estimated removal costs as authorized by the ICC. The estimated service lives for ComEd and PECO 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. See Note 18—Commitments and Contingencies for information regarding 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 5—Property, Plant and Equipment for further information regarding depreciation.

Amortization of regulatory assets is recorded over the recovery period specified in the related legislation or regulatory agreement. See Note 2—Regulatory Matters and 19—Supplemental Financial Information for additional information regarding Generation's nuclear fuel, Generation's ARC and the amortization of ComEd's and PECO's regulatory assets.

Asset Retirement Obligations (Exelon, Generation, ComEd and PECO)

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. Decommissioning cost studies are updated, on a rotational basis, for each of Generation's nuclear units at least every five years. Generation generally updates its ARO annually based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios. The liabilities associated with Exelon's non−nuclear AROs are adjusted on an ongoing rotational basis, at least once every five years.

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

Changes result from the passage of new laws and regulations and 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 12—Asset Retirement Obligations for additional information.

Capitalized Interest and AFUDC (Exelon, Generation, ComEd and PECO)

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 and PECO 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 as a charge 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 cost incurred, capitalized interest and credits to AFUDC by year:

		Exelon	Generation	ComEd	PECO
2011	Total incurred interest (a)	$ 783	$ 219	$ 349	$ 138
	Capitalized interest	49	49	—	—
	Credits to AFUDC debt and equity	25	—	12	13
2010	Total incurred interest (a)	$ 861	$ 191	$ 388	$ 197
	Capitalized interest	38	38	—	—
	Credits to AFUDC debt and equity	16	—	5	11
2009	Total incurred interest (a)	$ 786	$ 162	$ 322	$ 189
	Capitalized interest	50	49	—	—
	Credits to AFUDC debt and equity	14	—	8	6

(a) Includes interest expense to affiliates.

Guarantees (Exelon, Generation, ComEd and PECO)

The Registrants recognize, 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 the Registrants are released from risk under the guarantee. Depending on the nature of the guarantee, the release from risk of the Registrant may be recognized only upon the expiration or settlement of the guarantee or by a systematic and rational amortization method over the term of the guarantee. See Note 18—Commitments and Contingencies for additional information.

Asset Impairments (Exelon, Generation, ComEd and PECO)

Long−Lived Assets. The Registrants evaluate the carrying value of their long−lived assets, excluding goodwill, when circumstances indicate the carrying value of those assets may not be recoverable. See Note 5—Property, Plant and Equipment for a discussion of asset impairment evaluations made by Generation.

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 could reduce the fair value of a reporting unit below its carrying value. See Note 7—Intangible Assets for additional information regarding Exelon's and ComEd's goodwill.

Derivative Financial Instruments (Exelon, Generation, ComEd and PECO)

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 other derivative contracts that do not qualify or are not designated for hedge accounting, changes in the fair value of the derivatives are recognized in earnings each period. 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. Amounts classified in earnings are included in revenue, purchased power and fuel, or other, net on the Consolidated Statements 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 underlying nature of the Registrants' hedged items.

Revenues and expenses on 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 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 price is not tied to an unrelated underlying derivative. 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. If it were determined that a transaction designated as a normal purchase or a normal sale no longer met the 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 and PECO. See Note 9—Derivative Financial Instruments for additional information.

Retirement Benefits (Exelon, Generation, ComEd and PECO)

Generation, ComEd and PECO participate in Exelon's defined benefit pension plans and other postretirement plans. AmerGen sponsored a separate defined benefit pension plan and postretirement plan for its employees until the merger of AmerGen into Generation on January 8, 2009. Exelon became the sponsor of those plans at that date.

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 on pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the employees rather than immediately recognized in the income statement. See Note 13—Retirement Benefits for additional discussion of Exelon's accounting for retirement benefits.

New Accounting Pronouncements (Exelon, Generation, ComEd and PECO)

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

Fair Value Measurements

In May 2011, the FASB issued authoritative guidance amending existing guidance for measuring fair value and for disclosing information about fair value measurements. The FASB indicated that for many of the requirements it does not intend for the amendments to result in a change to current accounting. Required disclosures are expanded under the new guidance, especially for fair value measurements that are categorized within Level 3 of the fair value hierarchy, for which quantitative information about the unobservable inputs, the valuation processes used by the entity, and the sensitivity of the measurement to the unobservable inputs will be required. In addition, entities will be required to disclose the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed. The guidance is effective for the Registrants for periods beginning after December 15, 2011 and is required to be applied prospectively. The Registrants are not currently impacted by the changes regarding the measurement of fair value and will include the required disclosures in their March 31, 2012 Form 10−Q.

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. The guidance originally required entities to present reclassifications between net income and other comprehensive income at the financial statement line item level; however, in December 2011, the FASB deferred this requirement. This guidance is effective for the Registrants for periods beginning after December 15, 2011 and is required to be applied retroactively. Each of the Registrants currently presents a single statement of comprehensive income, consistent with the new guidance.

Goodwill Impairment Assessments

In September 2011, the FASB issued authoritative guidance amending existing guidance on the annual assessment of goodwill for impairment. Under the revised guidance, 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. This guidance is effective for Exelon and ComEd for periods beginning after December 15, 2011 and is not expected to have an impact on their consolidated financial statements.

Disclosures About Offsetting Assets and Liabilities

In December 2011, the FASB issued authoritative guidance requiring entities to expand disclosures about instruments and transactions eligible for offset in the Balance Sheet, and instruments and transactions subject to an agreement similar to a master netting arrangement. The required disclosures will include both gross and net information about instruments to which the guidance applies, including derivatives and securities borrowing and securities lending arrangements. This guidance is effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retroactively. As this guidance provides only disclosure requirements, the adoption of this standard will not impact the Registrants' results of operations, cash flows or financial positions.

2. Regulatory Matters (Exelon, Generation, ComEd and PECO)

The following matters below discuss, in all material respects, the current status of regulatory and legislative proceedings of the Registrants.

Illinois Regulatory Matters

Legislation to Modernize Electric Utility Infrastructure and to Update Illinois Ratemaking Process (Exelon and ComEd). On October 26, 2011, the Illinois General Assembly overrode the Governor's veto of the Illinois Energy Infrastructure Modernization Act (SB 1652), which became effective immediately. The Illinois General Assembly also passed House Bill 3036 (the Trailer Bill), which modifies and supplements SB 1652. The Governor signed the Trailer Bill into law on December 30, 2011. The combined legislation (EIMA) provides for substantial capital investment over a ten−year period to modernize Illinois' electric utility infrastructure and for greater certainty related to the recovery of costs by a utility through a pre−established formula rate tariff. On January 6, 2012, ComEd filed its Infrastructure Investment Plan with the ICC. Under the plan, ComEd will invest approximately $2.6 billion over the next 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. Approximately $1.3 billion will be invested in smart grid/smart meter technology that will place a smart meter with all customers and provide extensive customer education over the next nine years. The smart meter/smart grid technology is designed to significantly improve meter reading and to reduce the frequency and duration of outages. Approximately $1.3 billion will be invested to improve ComEd's infrastructure, including $200 million for storm hardening the distribution system. The January 6, 2012 filing with the ICC also included ComEd's $233 million investment plan for 2012. Implementation of the investment plan began in early 2012 and smart meter installation in homes and businesses is expected to begin later in 2012, subject to approval of

ComEd's AMI Deployment Plan by the ICC. Additionally, ComEd will contribute $10 million per year for five years, as long as EIMA remains in effect, to fund customer assistance programs for low−income customers, which amounts will not be recoverable through rates. ComEd will also make an initial contribution of $15 million to a new Science and Technology Innovation Trust fund that will be used to fund energy innovation. Subsequently, ComEd will make annual contributions to the fund of approximately $4 million for as long as the AMI Deployment Plan remains in effect.

EIMA provides for a performance−based distribution 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 this initial proceeding is to establish the formula under which rates will be calculated going−forward. The initial rate, which is expected to be lower than current rates but will be subject to reconciliation, will take effect within 30 days after the ICC order, which must be issued by May 31, 2012.

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 first year for which the reconciliation will be performed is 2011. ComEd will make its initial reconciliation filing in May 2012, and the rate adjustments necessary to reconcile 2011 revenues to ComEd's actual 2011 costs incurred will take effect in January 2013 after the ICC's review. As of December 31, 2011, ComEd recorded an estimated regulatory asset of $84 million and an offsetting increase in revenues for the 2011 reconciliation and net decrease in operating and maintenance expense for the deferral of certain storm costs of $29 million and $55 million, respectively. This regulatory asset represents ComEd's best estimate of the probable increase in distribution rates expected to be approved by the ICC to provide ComEd recovery of all prudently and reasonably incurred costs in 2011 and an earned rate of return on common equity, as defined in the legislation, for 2011. As the ICC proceeding to review ComEd's initially filed formula rate tariff progresses through May 2012, ComEd will adjust the estimated regulatory asset recorded as of December 31, 2011, to reflect any revisions made to the proposed formula by the ICC. ComEd currently does not anticipate any such adjustments would be material to its overall results of operations, financial position or cash flows. The positive impact of the reconciliation mechanism on ComEd's 2011 pre−tax income was partially offset by the recognition of the $15 million contribution to be made to the Science and Technology Innovation Trust fund discussed above.

Under the terms of EIMA, for the 2011 annual reconciliation period, ComEd's earned rate of return on common equity is required to be within plus or minus 50 basis points ("the collar") of the target rate determined as the annual average rate on 30−year treasury notes plus 590 basis points. Subsequent to the 2011 annual reconciliation period, the earned rate of return on common equity is required to be within the collar of the target rate determined as the annual average rate on 30−year treasury notes plus 580 basis points. In addition, the target rate of return on common equity is subject to reduction by up to 30 basis points each year beginning in 2013, gradually increasing to 38 basis points for each of the last four years, 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. The reliability metrics relate to improvements in outage frequency and duration and the customer service metrics relate to reductions in estimated bills, unaccounted for energy and uncollectible expense. EIMA also specifies the rate treatment for pension, incentive compensation and severance costs. In order to protect consumers, the legislation will terminate, ending ComEd's investment commitment, contribution commitments and the performance−based formula rates, (a) if the average residential rate increases by more than 2.5% annually from June 2011 through May 2014 or (b) at December 31, 2017 unless approved to continue by the Illinois General Assembly. There are additional restrictions and potential criteria for the program to end earlier than December 31, 2017.

Appeal of 2007 Illinois Electric Distribution Rate Case (Exelon and ComEd). 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). On January 25, 2011, ComEd filed a Petition for Leave to Appeal to the Illinois Supreme Court which was denied on March 30, 2011. The ICC has initiated a proceeding on remand. ComEd expects that the ICC will issue a final order in that proceeding in early 2012.

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). The Court's ruling may trigger a refund obligation. An interest charge may accrue on any refund amount. The impact on ComEd's rates and any associated refund obligation should be prospective from no earlier than the date of the Court's ruling on September 30, 2010. 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. If the ICC decides that refunds are required, ComEd's testimony stated that the maximum potential refund should be approximately $30 million. On November 10, 2011, the ALJ issued a proposed order in the remand proceeding agreeing with ComEd that the ICC does not have the legal authority to order a refund; a refund may only be ordered by a court. The ALJ also concluded that, to the extent that a court orders a refund, it should be in the amount of $37 million, including interest.

The Court also reversed the ICC's approval of ComEd's Rider SMP, a program which included the installation of 131,000 smart meters in the Chicago area. In 2009, the ICC approved a modified version of Rider SMP (Rider AMP). The Court held that the ICC's approval of Rider SMP constituted illegal single−issue ratemaking. The Court's decision prescribes a new, more stringent, standard for cost recovery riders not specifically authorized by statute. Such riders would be allowed only if: (1) the pass−through cost is imposed by an "external circumstance" and is unexpected, volatile, or fluctuating; and (2) recovery via rider does not change other expenses or increase utility income. Rider AMP is the subject of a separate appeal that is still pending. ComEd does not believe any of its other riders are affected by the Court's ruling.

Subsequent to the Court's ruling, ComEd filed a request with the ICC to allow it to request recovery, through inclusion in the 2010 Rate Case, of operating and maintenance costs that would have been recovered through Rider AMP, as well as continued rider recovery of carrying costs associated with capital investment in the ICC−approved AMI/Customer Applications pilot program until the conclusion of the 2010 Rate Case. The unrecovered Rider AMP pilot program costs had already been requested in rate base in the 2010 Rate Case. On December 2, 2010, the ICC approved ComEd's request. The investment and the pilot program costs were approved in the 2010 Rate Case proceeding.

ComEd has recognized for accounting purposes its best estimate of any refund obligation, subject to reconciliation when the ICC issues an order in the remand proceedings.

2010 Illinois Electric Distribution Rate Case (Exelon and ComEd). 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, 2011. The order also affirmed the current regulatory asset for severance costs, which was challenged by an intervenor 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 (Exelon and ComEd). 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, 2011, the balance of purchased accounts receivable associated with PORCB was $16 million. Under the tariff, ComEd recovers from RES and customers the costs for implementing and operating the program.

Recovery of Uncollectible Accounts (Exelon and ComEd). 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 (Exelon, Generation and ComEd). 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 December 21, 2010, the ICC approved the IPA's procurement plan covering the period June 2011 through May 2016. As of December 31, 2011, ComEd had completed the ICC−approved procurement process for its energy requirements through May 2012 as well as a portion of its requirements for each of the years ending in May 2013 and May 2014.

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. ComEd expects that the procurement events will take place 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, 2011, ComEd has completed the ICC−approved procurement process for RECs through May 2012. See Notes 9 – Derivative Financial Instruments for additional information regarding ComEd's financial swap contract with Generation and long−term renewable energy contracts.

On May 25, 2010, the ICC approved a Cash Working Capital (CWC) adjustment to be included in ComEd's energy procurement tariff; however, the ICC did not specify the amount of the allowed recovery, which will ultimately be determined in an annual procurement reconciliation proceeding, based on information from ComEd's most recent rate case. The approved CWC adjustment allows ComEd to recover the time value of money between when it is required to pay for supply−related costs and when those funds are actually received from customers. ComEd began billing customers for CWC through its energy procurement rider on June 1, 2010 reflecting the costs included in ComEd's original request to amend the tariff. Because of the uncertainty regarding the amount of CWC recovery, ComEd had been recording a reserve against a portion of these billings. The ICC order in the 2010 Rate Case clarified the method for determining CWC and, as a result, ComEd reversed a $17 million reserve during the second quarter of 2011.

Illinois Settlement Legislation (Exelon, Generation and ComEd). 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.

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

During the years ended 2010 and 2009, 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

Year Ended December 31, 2009	Generation	ComEd	Total Credits Issued to ComEd Customers
Credits to ComEd customers [a]	$ 45	$ 8	$ 53
Credits to other Illinois utilities' customers [a]	53	n/a	n/a
Other rate relief programs [b]	—	1	n/a
Total incurred costs	$ 98	$ 9	$ 53

(a) Recorded as a reduction in operating revenues.
(b) Recorded as a charge to operating and maintenance expense.

Energy Efficiency and Renewable Energy Resources (Exelon and ComEd). 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, subject to customer rate cap limitations. All goals are subject to rate impact criteria set forth in the Illinois Settlement Legislation. As of December 31, 2011, 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 18—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 (Exelon and PECO). 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 prior tax years 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 will be reflected in customer bills beginning January 1, 2012. Tax benefits claimed prospectively as a result of Revenue Procedure 2011−43 will be reflected as a reduction to income tax expense in the year in which it is claimed on the tax return and will be reflected in the determination of revenue requirements in the next electric distribution base rate case. The IRS anticipates issuing guidance in 2012 on the appropriate tax treatment of repair costs for gas distribution assets. See Note 11 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 (Exelon and PECO). PECO's 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. Under the DSP Program, 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. The filing and implementation costs of the DSP Program were recorded as a noncurrent regulatory asset and are being recovered through the GSA over its 29−month term. During 2011, PECO entered into contracts with PAPUC−approved bidders for its fifth and sixth competitive procurements of electric supply for default electric service, which included hourly spot market price full requirements contracts for its large commercial and industrial procurement classes that commenced June 2011, block contracts for the residential procurement class that commenced June and December 2011, and full requirements fixed price contracts for the residential, small and medium commercial procurement classes commencing June 2012. Under the full requirements contracts, default service suppliers must provide electric supply, capacity, transmission other than Network Integration Transmission Service, ancillary services, transmission and distribution losses, congestion management costs and AECs for compliance with the AEPS Act. PECO will conduct three additional competitive procurements over the remainder of the term of the DSP Program.

On April 15, 2011, the PAPUC issued an order approving the joint petition for partial settlement of the initial dynamic pricing and customer acceptance plan and ruled that the administrative costs be recovered from default service customers through the GSA.

On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC. The plan outlined how PECO will purchase electricity for default customers from June 1, 2013 through May 31, 2015. To continue to ensure a competitive procurement process for residential customers, PECO proposed to procure electricity through a combination of one−year and two−year fixed full requirements contracts, reduce the amount of time between when the energy is purchased and when it is provided to customers and complete an annual, rather than quarterly, reconciliation of costs for actual versus forecasted energy use. Hearings on the filing will be held in the summer of 2012, with a PAPUC ruling expected in mid−October 2012.

Purchase of Receivables Program (Exelon and PECO). PECO’s revised electric and gas POR programs, approved by the PAPUC in June and December 2010, respectively, require PECO to purchase the customer accounts receivable of EGSs and natural gas suppliers that participate in customer choice programs and have elected consolidated billing by PECO. The revised POR programs provide for full recovery of PECO’s system implementation costs for program administration through a temporary discount on purchased receivables and allow PECO to terminate service to customers beginning on the effective date, based on unpaid charges for electric supply or natural gas, and permit recovery of uncollectible accounts expense from customers through distribution rates. PECO’s revised electric POR program became effective on January 1, 2011. PECO’s gas POR program became effective on January 1, 2012.

Purchased receivables at December 31, 2011 were $47 million, net of an allowance for uncollectible accounts of $5 million. Purchased receivables at December 31, 2010 were $3 million, net of an allowance for uncollectible accounts of less than $1 million. The increase in the purchased receivables balance is a result of increased electric customer choice program participation following the expiration of the transition period. Prior to participation in the customer choice program, these receivables would have been recorded in customer accounts receivable. Purchased receivables are classified in other accounts receivable, net on Exelon’s and PECO’s Consolidated Balance Sheets.

Smart Meter and Smart Grid Investments (Exelon and PECO). In April 2010, the PAPUC approved PECO’s $550 million Smart Meter Procurement and Installation Plan under which PECO will install more than 1.6 million smart meters and deploy advanced communication networks by 2020. 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. As a result of the SGIG funding, PECO will deploy 600,000 smart meters by 2013, deploy more than 1.6 million smart meters by 2020 and increase smart grid investments to approximately $100 million by 2013. The $200 million SGIG funds will be reimbursed ratably based on projected spending of more than $400 million, which includes approximately $7 million related to demonstration projects by two sub−recipients. The SGIG is non−taxable based on IRS guidance. The DOE has a conditional ownership interest in Federally−funded project property and equipment, which is subordinate to PECO's existing mortgage. In total, through 2020, PECO plans to spend up to $650 million on its smart grid and smart meter infrastructure. The $200 million SGIG from the DOE will be used to significantly reduce the impact of those investments on PECO ratepayers.

As of December 31, 2011, PECO received $64 million in reimbursements and had $29 million in outstanding receivables from the DOE for reimbursable costs, which are recorded in other accounts receivable, net on Exelon's and PECO's Consolidated Balance Sheets.

Energy Efficiency Programs (Exelon and PECO). PECO's PAPUC−approved EE&C Plan has a four−year term that began on June 1, 2009 and totals more than $328 million pursuant to Act 129's EE&C reduction targets. The plan sets forth how PECO will reduce electric consumption by 1% and 3% in its service territory by May 31, 2011 and May 31, 2013, respectively and reduce peak demand by a minimum of 4.5% of PECO's annual system peak demand in the 100 hours of highest demand by May 31, 2013, measured against its peak demand during the period of June 1, 2007 through May 31, 2008. If PECO fails to achieve the required reductions in consumption within the stated deadlines, PECO will be subject to civil penalties of up to $20 million, which would not be recoverable from ratepayers.

The plan also includes a CFL program, weatherization programs, an energy efficiency appliance rebate and recycling program and rebates 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.

As of May 31, 2011, PECO had exceeded the 1% energy use reduction target. On August 18, 2011, the PAPUC approved filed adjustments to the EE&C Plan that will allow PECO to meet its May 31, 2013 targets for energy use and energy demand reductions while remaining within its approved budget.

Alternative Energy Portfolio Standards (Exelon and PECO). 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 8.0% and the requirement for Tier II alternative energy resources ranges from 6.2% to 10.0%. 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. In May 2011, PECO procured 340,000 Tier II AECs that are being used to meet AEPS Act obligations for the compliance years ending May 2011 and May 2012. 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 ending May 2012 and May 2013, which was approved by the PAPUC on January 17, 2012.

Administrative costs and the costs of the banked AECs were recovered with a return on the unamortized balance over a twelve−month period that ended December, 31, 2011. 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 proposed in its Default Service Plan filed on January 13, 2012 to eliminate the AEPS rider and recover AEPS compliance costs through the GSA.

Natural Gas Choice Supplier Tariff (Exelon and PECO). 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 expects to notify impacted NGSs of their new collateral levels by March 31, 2012.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). 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 December 15, 2011, the PAPUC adopted a final order providing guidance to the state's electric distribution companies in developing their default service plans for the period beginning January 1, 2013. The PAPUC also issued for comment a tentative order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company's default service plan beginning in 2013, with the exception of a Retail Opt−in Auction Program and Standard Offer Customer Referral Program, which it proposed for inclusion in the 2013 plan. Final guidance on long−term structural changes is expected to be issued in 2012. On January 13, 2012, PECO filed its second Default Service Plan for approval with the PAPUC, which proposed 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.

Pennsylvania House Bill No. 1294 (Exelon and PECO). On January 25, 2012, House Bill No. 1294 (HB 1294) was passed by the Pennsylvania State Senate. The House of Representatives approved the legislation through a concurrence vote and now it goes to the Governor for his signature. HB 1294 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.

In order to qualify for the DSIC under HB 1294, utilities are required to submit a long−term infrastructure improvement plan, which will be reviewed by the PAPUC every 5 years, and a certification that a base rate case has been or will be filed within 5 years. The DSIC cannot exceed 5% of distribution rates and will be reset to zero if the utility's return on equity exceeds the allowable rate of return under the DSIC. Utilities can petition the PAPUC for a waiver to the 5% cap.

HB 1294 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 future test year.

Federal Regulatory Matters

Transmission Formula Rate (Exelon and ComEd). ComEd's transmission rates are established based on a FERC−approved formula. ComEd's most recent annual formula rate update filed in May 2011 reflects actual 2010 expenses and investments plus forecasted 2011 capital additions. The update resulted in a 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. This compares to the May 2010 updated revenue requirement of $416 million. The increase in the revenue requirement was primarily driven by the Illinois income tax statutory rate change enacted in January 2011. The 2011 net revenue requirement became effective June 1, 2011 and is recovered over the period extending through May 31, 2012. 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 9.10%, a decrease from the 9.27% 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%.

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd and PECO). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd and PECO 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. In the short term, based on new transmission facilities approved by PJM, it is likely that allocating across PJM the costs of new facilities 500 kV and above will increase charges to ComEd and reduce charges to PECO, as compared to the allocation methodology in effect before the FERC order. 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. In May and June 2010, certain parties, including Exelon, submitted testimony to supplement the record. 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.

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

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

	Total	2012	2013	2014	2015	2016
ComEd	$242	$ 73	$104	$ 41	$ 12	$ 12
PECO	87	30	18	12	13	14

PJM Minimum Offer Price Rule (Exelon and Generation). 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. On February 1, 2011, in response to the enactment of New Jersey Senate Bill 2381, Generation joined a group of generating companies, PJM Power Providers Group (P3), in filing a complaint asking FERC to revise PJM's MOPR to mitigate this exercise of buyer market power. In response to P3's complaint, PJM filed a tariff amendment on February 11, 2011, to improve the MOPR. PJM's filing differs from P3's proposal, but in general P3 supports PJM's filing. P3 and PJM requested that FERC act on the proposed tariff amendment prior to the May 2011 capacity auction. A number of state regulators and consumer groups have opposed tariff changes, but these changes are in line with recent FERC orders regarding capacity markets in the New York and New England ISOs. On April 12, 2011, FERC issued an order revising PJM's MOPR to mitigate the exercise of buyer market power. Included in the FERC order was a revision to the MOPR whereby a subsidized plant cannot submit a bid into the auction for less than 90% of the cost of new entry of a plant of that type, unless the unit can justify a lower bid based on its costs. The minimum offer limitation continues until a unit clears the base residual RPM auction for the first time. After a unit clears once, it may bid in at any price, including zero. This may help reduce the magnitude of artificial suppression of capacity auction prices created by the actions of state regulators such as the capacity legislation in New Jersey. A number of parties filed rehearing of the FERC order on several different issues, including the question of whether the minimum price mitigation should apply to load serving entities that self−supply capacity. FERC scheduled the issue for consideration at a technical conference, while rehearing is pending. On November 17, 2011, the Commission issued an order on rehearing, that, among other things, denied rehearing on the central issues, including application of the MOPR to self−supply capacity and to state sponsored capacity. A number of parties filed petitions for review in the Courts of Appeals for the D.C. Circuit and the Third Circuit, all of which are currently pending in the Third Circuit. The case likely will not be resolved by the Court until the second half of 2012 or early 2013.

Market−Based Rates (Exelon, Generation, ComEd and PECO). Generation, ComEd and PECO 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 and PECO 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 or PECO has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds 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 and PECO have filed market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd and PECO 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 January 15, 2009 and September 2, 2009 and accepted the 2009 filing on October 26, 2009, 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. In that updated analysis, Generation informed FERC that its market share data in PJM would change beginning in 2011, when Generation's contract for PECO's full requirements for capacity and energy expired. The FERC Staff asked for a letter describing the amount of capacity affected by the PECO contract expiration and alternative transactions, which Generation filed on March 21, 2011. The impact of that change, as well as any new sales contracts or other intervening changes in Generation's market share, will be reflected in the next updated market share screen analysis due to be filed at the end of 2013. On June 22, 2011, FERC issued an order confirming Generation's continued authority to charge market based rates, stating that any market power concerns are adequately addressed by PJM's monitoring and mitigation programs.

Reliability Pricing Model (Exelon and Generation). 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, 2015 occurred in May 2011. While certain state commissions, consumer advocates and trade associations continue to object to the PJM capacity market construct, their most recent challenge to auction results ran its course when the D. C. Circuit, on February 8, 2011, denied a petition to review the Commission's dismissal of their complaint.

License Renewals (Exelon and Generation). 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. See Note 18—Commitments and Contingencies for additional information.

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 NRC is expected to spend a total of 22 to 30 months to review the applications before making a decision. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively.

Regulatory Assets and Liabilities (Exelon, ComEd and PECO)

Exelon, ComEd and PECO prepare their 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.

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

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd and PECO as of December 31, 2011 and 2010.

December 31, 2011	Exelon	ComEd	PECO
Regulatory assets			
Pension and other postretirement benefits	$2,998	$ —	$ 7
Deferred income taxes	1,181	71	1,110
AMI and smart meter programs	30	8	22
Under−recovered distribution services costs	84	84	—
Debt costs	99	88	11
Severance	63	63	—
Asset retirement obligations	74	50	24
MGP remediation costs	159	115	44
RTO start−up costs	7	7	—
Financial swap with Generation—noncurrent	—	191	—
Renewable energy and associated RECs—noncurrent	97	97	—
DSP Program costs	5	—	5
Other	42	22	20
Noncurrent regulatory assets	4,839	796	1,243
Financial swap with Generation—current	—	503	—
Under−recovered energy and transmission costs	57	48	9
Under−recovered electric universal service fund costs	3	—	3
Renewable energy and associated RECs—current	9	9	—
Current regulatory assets	69	560	12
Total regulatory assets	$4,908	$1,356	$1,255
Regulatory liabilities			
Nuclear decommissioning	$2,222	$1,857	$ 365
Removal costs	1,246	1,246	—
Energy efficiency and demand response programs	118	49	69
Electric distribution tax repairs	170	—	170
Over−recovered uncollectible accounts	15	15	—
Noncurrent regulatory liabilities	3,771	3,167	604
Over−recovered energy and transmission costs	42	12	30
Over−recovered gas universal service fund costs	3	—	3
Over−recovered AEPS costs	8	—	8
Current regulatory liabilities	53	12	41
Total regulatory liabilities	$3,824	$3,179	$ 645

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

Table of Contents

December 31, 2010	Exelon	ComEd	PECO
Regulatory assets			
Pension and other postretirement benefits	$2,763	$ —	$ 13
Deferred income taxes	852	23	829
AMI and smart meter program expenses	17	—	17
Debt costs	123	108	15
Severance	74	74	—
Asset retirement obligations	86	61	25
MGP remediation costs	149	110	39
RTO start−up costs	10	10	—
Under−recovered uncollectible accounts	14	14	—
Financial swap with Generation—noncurrent	—	525	—
DSP Program costs	7	—	7
Other	45	22	23
Noncurrent regulatory assets	4,140	947	968
Financial swap with Generation—current	—	450	—
Under−recovered energy and transmission costs	6	6	—
DSP Program electric procurement contracts	4	—	9
Current regulatory assets	10	456	9
Total regulatory assets	$4,150	$1,403	$977
Regulatory liabilities			
Nuclear decommissioning	$2,267	$1,892	$375
Removal costs	1,211	1,211	—
Renewable energy and associated RECs—noncurrent	4	4	—
Energy efficiency and demand response programs	69	31	38
Other	4	(1)	5
Noncurrent regulatory liabilities	3,555	3,137	418
Over−recovered energy and transmission costs	44	19	25
Current regulatory liabilities	44	19	25
Total regulatory liabilities	$3,599	$3,156	$443

Pension and other postretirement benefits. As of December 31, 2011, $2,991 million represents regulatory assets related to the recognition of ComEd's and PECO's respective shares of the underfunded status of Exelon's defined benefit postretirement plans as a liability on Exelon's balance sheet. The regulatory asset is amortized in proportion to the recognition of prior service costs (gains), transition obligations and actuarial losses attributable to ComEd's pension plan and ComEd's and PECO's other postretirement benefit plans determined by the cost recognition provisions of the authoritative guidance for pensions and postretirement benefits. ComEd and PECO will recover these costs through base rates as allowed in their most recently approved regulated rate orders. See Note 13 –Retirement Benefits for additional detail. In addition, $7 million is the result of PECO transitioning to the current authoritative guidance in 1993, which is recoverable in rates through 2012. ComEd and PECO are not earning a return on the recovery of these costs in base rates.

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 and PAPUC, as well as the revenue impacts thereon, and assume continued recovery of these costs in future transmission and distribution rates. For ComEd, 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. See Note 11—Income Taxes and Note 13—Retirement Benefits for additional information. ComEd and PECO are not earning a return on the recovery of these costs.

AMI and smart meter 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. 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, and recovery of accelerated depreciation on PECO's current meter assets over a 10−year period ending December 31, 2020.

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, 2011, the regulatory asset was comprised of $29 million for the annual reconciliation and $55 million related to significant storms.

Debt costs. Consistent with rate recovery for ratemaking purposes, ComEd's and PECO'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.

Severance. 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.

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 12—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. 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. See Note 18—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 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.

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 begins in June 2012. 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 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.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

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 ending December 31, 2012. ComEd and PECO do not earn a return on the recovery of these 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.

Under (Over)−recovered energy and transmission costs current asset (liability). 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, 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.

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 12—Asset Retirement Obligations for additional information.

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

Energy efficiency and demand response programs. These amounts represent costs recoverable (refundable) under ComEd's ICC approved Energy Efficiency and Demand Response Plan and PECO's PAPUC−approved EE&C Plan. 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 six months following the expiration of the program.

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

Electric distribution tax repairs. PECO' 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 will be reflected in customer bills beginning January 1, 2012. No interest will be paid to customers.

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, 2011, 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.

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.

Operating and Maintenance for Regulatory Required Programs (Exelon, ComEd and PECO)

The following tables set forth costs for various legislative and/or regulatory programs that are recoverable from customers on a full and current basis through a rider for ComEd and PECO for the years ended December 31, 2011, 2010 and 2009. An equal and offsetting amount has been reflected in operating revenues during the periods.

For the Year Ended December 31, 2011	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 162	$ 110[(a)]	$ 52
Smart meter program	9	—	9
Purchased power administrative costs	10	5	5
AEPS administrative costs	1	—	1
Consumer education program	2	—	2
Total operating and maintenance for regulatory required programs	$ 184	$ 115	$ 69

For the Year Ended December 31, 2010	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 135	$ 85[(a)]	$ 50
Advanced metering infrastructure pilot program	5	5	—
Purchased power administrative costs	4	4	—
Consumer education program	3	—	3
Total operating and maintenance for regulatory required programs	$ 147	$ 94	$ 53

For the Year Ended December 31, 2009	Exelon	ComEd	PECO
Energy efficiency and demand response programs	$ 59	$ 59[(a)]	$ —
Purchased power administrative costs	4	4	—
Total operating and maintenance for regulatory required programs	$ 63	$ 63	$ —

(a) As a result of the Illinois Settlement, utilities are required to provide energy efficiency and demand response programs.

3. Merger and Acquisitions (Exelon and Generation)

Proposed Merger with Constellation Energy Group, Inc. (Exelon)

On April 28, 2011, Exelon and Constellation Energy Group, Inc. (Constellation) announced that they signed an agreement and plan of merger to combine the two companies in a stock−for−stock transaction. Under the merger agreement, Constellation's shareholders will receive 0.930 shares of Exelon common stock in exchange for each share of Constellation common stock. Based on Exelon's closing share price on April 27, 2011, Constellation shareholders would receive $7.9 billion in total equity value. The resulting company will retain the Exelon name and be headquartered in Chicago. The transaction requires the approval by the shareholders of both Exelon and Constellation. Completion of the transaction is also conditioned upon review of the transaction by the U.S. Department of Justice (DOJ) and approval by the FERC, NRC, Maryland Public Service Commission (MDPSC), the New York Public Service Commission (NYPSC), the Public Utility Commission of Texas (PUCT), and other state and federal regulatory bodies. As of February 9, 2012, Exelon and Constellation have received approval of the transaction from the shareholders of Exelon and Constellation, DOJ, PUCT and the NYPSC. Exelon and Constellation are awaiting final approval of the transaction from the MDPSC, FERC and NRC.

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 New York ISO from September 2007 through December 2008. Exelon continues to evaluate the matter in order to make an assessment regarding (1) the likely outcome of the investigation and (2) whether the ultimate resolution of the investigation will be material to the results of operations, cash flows, or financial condition of Constellation before the merger or Exelon after the merger. Absent any delay in the FERC approval process, the companies anticipate closing the transaction in the first quarter of 2012.

Associated with certain of the regulatory approvals required for the merger, the companies have proposed to divest three Constellation generating stations located in PJM, which is the only market where there is a material overlap of generation owned by both companies. 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. In October 2011, Exelon and Constellation reached a settlement with the PJM Independent Market Monitor, who had previously raised market power concerns regarding the merger. The settlement contains a number of commitments by the merged company, including limiting the universe of potential buyers of the divested assets to entities without significant market shares in the relevant PJM markets. The settlement also includes assurances about how the merged company will bid its units into the PJM markets. The proposed divestiture and the settlement with the PJM Market Monitor were filed with FERC and the MDPSC and are included in their decisions to issue a final order approving the merger.

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 pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon and Constellation have proposed a package of benefits to Baltimore Gas and Electric Company (BGE) customers, the City of Baltimore and the state of Maryland, which results in a direct investment in the state of Maryland of more than $1 billion. This investment includes capital projects including development of new renewable and gas−fired generation in Maryland, representing a substantial portion of the investment.

In addition, in January 2012 Exelon and Constellation reached an agreement with Electricite de France (EDF) under which EDF has withdrawn its opposition to the Exelon−Constellation merger. The terms address Constellation Energy Nuclear Group (CENG), a joint venture between Constellation and EDF that owns and operates three nuclear facilities with 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 significant impact on Exelon 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 is disclosed and sought rescission of the proposed merger. During the third quarter, the parties to the suits reached an agreement in principle to settle the suits through additional disclosures to Constellation shareholders. The settlement is subject to court approval.

Through December 31, 2011, Exelon has incurred approximately $77 million of expense associated with the transaction, primarily related to fees incurred as part of the acquisition. Under the merger agreement, in the event Exelon or Constellation terminates the merger agreement to accept a superior proposal, or under certain other circumstances, Exelon or Constellation, as applicable, would be required to pay a termination fee of $800 million in the case of a termination fee payable by Exelon to Constellation or a termination fee of $200 million in the case of a termination fee payable by Constellation to Exelon.

Acquisitions (Exelon and Generation)

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; 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.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

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	Shooting Star	Exelon Wind
Fair value of consideration transferred				
Cash	$ 305	$ 75	$ 3	$ 893
Plus: Gain on PPA settlement	6	—	—	—
Contingent consideration [(a)]	—	—	9	32
Total fair value of consideration transferred	$ 311	$ 75	$ 12	$ 925
Recognized amounts of identifiable assets acquired and liabilities assumed				
Property, plant and equipment	$ 347	$ 15	$ 12	$ 700
Inventory	5	—	—	—
Intangible assets [(b)]	—	190	—	224
Payable to First Solar, Inc. [(c)]	—	(135)	—	—
Working capital, net [(d)]	(5)	—	—	18
Asset retirement obligations	—	—	—	(13)
Noncontrolling interest	—	—	—	(3)
Other Assets	—	5	—	(1)
Total net identifiable assets	$ 347	$ 75	$ 12	$ 925
Bargain purchase gain	$ 36	$ —	$ —	$ —

(a) For the Shooting Star acquisition, the balance includes $4 million of cash placed in escrow which will be paid to Infinity Wind Holdings, LLC upon commencement of construction.
(b) See Note 7—Intangible Assets for additional information.
(c) 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.
(d) Working capital acquired for Wolf Hollow is subject to a 180−day adjustment period.

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, pursuant to which Generation added 720 MWs of capacity within the ERCOT power market. The acquisition supports the Exelon commitment to clean energy as part of Exelon 2020. In connection with the acquisition, Generation terminated and settled its existing long−term PPA with Wolf Hollow, resulting in a gain of approximately $6 million, which is included within operating revenues (other revenue) in Exelon and Generation’s Consolidated Statements of Operations and Comprehensive Income.

Generation recognized an approximately $36 million non−cash bargain purchase gain (i.e., negative goodwill). Increases in observable forward market power prices since the May 2011 transaction announcement date, primarily reflecting the impact on the Texas power markets of the Cross−State Air Pollution Rule (CSAPR) final regulations issued by the EPA in July 2011, as well as sustained hot weather in Texas, resulted in an increase in the fair value of the net assets as of the acquisition date, resulting in the bargain purchase gain. The gain was included within other, net in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

The fair value of the assets acquired included receivables for insurance claims of $14 million shown in working capital above. This amount represents insured repair costs incurred prior to the acquisition date, less the applicable deductible. As of December 31, 2011, approximately $4 million remains outstanding, which Generation expects to collect during the first quarter of 2012.

Wolf Hollow's revenue and operating income contribution to Exelon and Generation for the period from August 25, 2011 to December 31, 2011 was approximately $30 million and $(5) million, respectively. The unaudited pro forma results for Exelon and Generation as if the Wolf Hollow acquisition occurred on January 1, 2010 were not materially different from Exelon and Generation's financial results for the years ended December 31, 2011 and 2010. Exelon and Generation incurred approximately $4 million of acquisition−related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

Antelope Valley Solar Ranch One. On September 30, 2011, Exelon announced the completion of its acquisition of all of the interests in 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, Inc., which developed and will build, operate, and maintain the project. Construction has started, with the first portion of the project expected to come online in late 2012 and full operation planned for late 2013. The acquisition supports the Exelon commitment to clean energy as part of Exelon 2020. The project has a 25−year PPA, approved by the California Public Utilities Commission (CPUC), with Pacific Gas & Electric Company for the full output of the plant.

Exelon expects to invest up to $713 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. An initial DOE Loan advance was expected to be made during the fourth quarter of 2011, but was delayed by the DOE pending resolution of an outstanding construction permit issue. While the construction permit may constitute a technical default under the loan guarantee agreement, based on discussions with the governmental body that issued the permit, Exelon believes a ministerial change to the permit should resolve the issue. DOE was notified of this issue and has extended to April 6, 2012 the date by which the initial loan advance must be funded. See Note 10 – Debt and Credit Agreements for additional information on the DOE loan guarantee. The original purchase agreement also contained a provision that First Solar, Inc. will repurchase Antelope Valley if initial funding of the loan does not occur by January 10, 2012. However, the purchase agreement has been amended to extend this date to February 24, 2012 or such later date as may be agreed by Exelon and First Solar, Inc. If this date is not extended further, First Solar, Inc. would repurchase Antelope Valley for the purchase price paid by Exelon and certain other costs incurred by Exelon related to the project.

In 2011, Exelon and Generation incurred approximately $8 million of acquisition−related costs associated with this transaction. These costs are included within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Shooting Star Wind Project, LLC. On December 7, 2011, Exelon Wind and Infinity Wind Holdings, LLC (Infinity Wind) entered into a purchase agreement by which Exelon Wind purchased all of the membership interests in Shooting Star Wind Project, LLC (Shooting Star), a 104−MW wind power generation project in Kiowa County, Kansas. Shooting Star is in the development stage and backed by a 20−year PPA with Mid−Kansas Electric Company for 100% of the net energy, capacity, ancillaries, and green tags produced. The project will require a total investment of approximately $148 million and is expected to achieve commercial operation in the fourth quarter of 2012.

Exelon Wind. On December 9, 2010, Generation completed 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, $2 million was recorded in operating and maintenance expense within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income and the contingent consideration included within other current liabilities within Exelon and Generation's Consolidated Balance Sheets was adjusted to $10 million to reflect the full expected contingent payment related to the Harvest II project. The remaining $8 million of contingent consideration is included in other current liabilities within Exelon and Generation'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 unaudited pro forma results for Exelon and Generation prepared as if the Exelon Wind acquisition occurred on January 1, 2009 were not materially different from Exelon's and Generation's financial results for the years ended December 31, 2010 and 2009.

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

4. Accounts Receivable (Exelon, Generation, ComEd and PECO)

Accounts receivable at December 31, 2011 and 2010 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:

2011	Exelon	Generation	ComEd	PECO
Unbilled customer revenues	$ 902	$ 493	$ 246	$ 163
Allowance for uncollectible accounts (a)	(199)	(29)	(78)	(92)(b)

2010	Exelon	Generation	ComEd	PECO
Unbilled customer revenues	$1,060	$ 407	$ 304	$ 349
Allowance for uncollectible accounts (a)	(211)	(32)	(80)	(99)(b)

(a) Includes the allowance for uncollectible accounts on customer and other accounts receivable.
(b) Includes an allowance for uncollectible accounts of $8 million and $2 million at December 31, 2011 and December 31, 2010, respectively, related to PECO's current installment plan receivables described below.

PECO Installment Plan Receivables (Exelon and PECO). 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 $21 million and $22 million as of December 31, 2011 and December 31, 2010, 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, 2011 of $17 million consists of $1 million, $3 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2010 of $19 million consists of $1 million, $5 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, 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 (Exelon and PECO). 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. As of December 31, 2011 and December 31, 2010, the financial institution's undivided interest in Exelon and PECO's gross accounts receivable was equivalent to $329 million and $346 million, respectively, which is calculated under the terms of the agreement. See Note 10—Debt and Credit Agreements for additional information regarding the accounts receivable agreement.

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

5. Property, Plant and Equipment (Exelon, Generation, ComEd and PECO)

Exelon

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2011 and 2010:

	Average Service Life (years)	2011	2010
Asset Category			
Electric—transmission and distribution	5 −75	$21,716	$20,389
Electric—generation (a)	1 −54	13,682	11,914
Gas—transportation and distribution	5 −70	1,793	1,732
Common—electric and gas	5 −50	564	534
Nuclear fuel (b)	1 − 8	4,225	3,725
Construction work in progress	N/A	1,110	1,290
Other property, plant and equipment (c)	4 −50	439	421
Total property, plant and equipment		43,529	40,005
Less: accumulated depreciation (d)		10,959	10,064
Property, plant and equipment, net		$32,570	$29,941

(a) Includes assets acquired through acquisitions. See Note 3—Acquisition for additional information.
(b) Includes nuclear fuel that is in the fabrication and installation phase of $674 million and $651 million at December 31, 2011 and 2010, respectively.
(c) Includes Generation's buildings under capital lease with a net carrying value of $23 million and $26 million at December 31, 2011 and 2010, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $30 million and $27 million as of December 31, 2011 and 2010, respectively. Also includes unregulated property at ComEd and PECO.
(d) Includes accumulated amortization of nuclear fuel in the reactor core at Generation of $1,784 million and $1,592 million as of December 31, 2011 and 2010, 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	2011	2010	2009
Electric—transmission and distribution	2.59%	2.53%	2.43%
Electric—generation	3.12%	2.86%	2.28%
Gas	1.73%	1.75%	1.75%
Common—electric and gas	8.05%	7.25%	6.41%

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

Generation

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2011 and 2010:

	Average Service Life (years)	2011	2010
Asset Category [(a)]			
Electric—generation	1 −54	$13,682	$11,914
Nuclear fuel [(b)]	1 − 8	4,225	3,725
Construction work in progress	N/A	827	849
Other property, plant and equipment [(c)]	4 −22	54	54
Total property, plant and equipment		18,788	16,542
Less: accumulated depreciation [(d)]		5,313	4,880
Property, plant and equipment, net		$13,475	$11,662

(a) Includes assets acquired through acquisitions. See Note 3—Acquisition for additional information.
(b) Includes nuclear fuel that is in the fabrication and installation phase of $674 million and $651 million at December 31, 2011 and 2010, respectively.
(c) Includes buildings under capital lease with a net carrying value of $23 million and $26 million at December 31, 2011 and 2010, respectively. The original cost basis of the buildings was $53 million and total accumulated amortization was $30 million and $27 million as of December 31, 2011 and 2010, respectively.
(d) Includes accumulated amortization of nuclear fuel in the reactor core of $1,784 million and $1,592 million as of December 31, 2011 and 2010, respectively.

The annual depreciation provisions as a percentage of average service life for electric generation assets were 3.12%, 2.86% and 2.28% for the years ended December 31, 2011, 2010 and 2009, 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. See Note 18—Commitments and Contingencies for additional information regarding Oyster Creek. As a result, the receipt of license renewals has no impact on the Consolidated Statements of Operations. See Note 2—Regulatory Matters for additional information regarding license renewals.

Long−Lived Asset Impairments. Due to the continued decline in forward energy prices in the first quarter of 2009, Generation evaluated its Texas plants for recoverability as of March 31, 2009. As the estimated undiscounted future cash flows and fair value of the Handley and Mountain Creek stations were less than the stations' carrying values, the stations were determined to be impaired at March 31, 2009. LaPorte station was determined not to be impaired. Accordingly, the Handley and Mountain Creek stations were written down to fair value, and an impairment charge of $223 million was recorded in operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations in the first quarter of 2009. The fair value of the stations was determined using the income (discounted cash flow), market (available comparables) and cost (replacement cost) valuation approaches.

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

Table of Contents

ComEd

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2011 and 2010:

	Average Service Life (years)	2011	2010
Asset Category			
Electric—transmission and distribution	5 −75	$15,637	$14,752
Construction work in progress	N/A	187	207
Other property, plant and equipment (a)	50	47	47
Total property, plant and equipment		15,871	15,006
Less: accumulated depreciation		2,750	2,428
Property, plant and equipment, net		$13,121	$12,578

(a) Represents unregulated property.

The annual depreciation provisions as a percentage of average service life for electric transmission and distribution assets were 2.67%, 2.64% and 2.57% for the years ended December 31, 2011, 2010 and 2009, respectively.

PECO

The following table presents a summary of property, plant and equipment by asset category as of December 31, 2011 and 2010:

	Average Service Life (years)	2011	2010
Asset Category			
Electric—transmission and distribution	5 −65	$6,079	$5,637
Gas—transportation and distribution	5 −70	1,793	1,732
Common—electric and gas	5 −50	564	534
Construction work in progress	N/A	83	231
Other property, plant and equipment (a)	50	17	17
Total property, plant and equipment		8,536	8,151
Less: accumulated depreciation		2,662	2,531
Property, plant and equipment, net		$5,874	$5,620

(a) Represents unregulated property.

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

The following table presents the annual depreciation provisions as a percentage of average service life for each asset category.

Average Service Life Percentage by Asset Category	2011	2010	2009
Electric—transmission and distribution	2.33%	2.17%	1.97%
Gas	1.73%	1.75%	1.75%
Common—electric and gas	8.05%	7.25%	6.41%

See Note 1—Significant Accounting Polices for further information regarding property, plant and equipment policies and accounting for capitalized software costs for Exelon, Generation, ComEd and PECO. See Note 10—Debt and Credit Agreements for further information regarding Exelon's, ComEd's and PECO's property, plant and equipment subject to mortgage liens.

6. Jointly Owned Electric Utility Plant (Exelon, Generation and PECO)

Exelon's, Generation's and PECO's undivided ownership interests in jointly owned electric plants and transmission facilities at December 31, 2011 and 2010 were as follows:

	Nuclear generation			Fossil fuel generation			Transmission		Other
	Quad Cities	Peach Bottom	Salem (a)	Keystone	Conemaugh	Wyman	PA (b)	DE/NJ (c)	Other (d)
Operator	Generation	Generation	PSEG Nuclear	GenOn	GenOn	FP&L	First Energy	PSEG	
Ownership interest	75.00%	50.00%	42.59%	20.99%	20.72%	5.89%	Various	42.55%	44.24%
Exelon's share at December 31, 2011:									
Plant	$ 822	$ 650	$ 420	$ 366	$ 271	$ 3	$ 5	$ 66	$ 1
Accumulated depreciation	156	285	103	137	154	3	3	33	—
Construction work in progress	37	111	61	5	15	—	—	—	—
Exelon's share at December 31, 2010:									
Plant	$ 709	$ 566	$ 395	$ 360	$ 247	$ 3	$ 8	$ 60	$ 1
Accumulated depreciation	124	274	96	128	152	2	5	29	—
Construction work in progress	63	88	72	3	11	—	—	—	—

(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, 2011 and 2010.
(b) PECO owns a 22% share in 127 miles of 500 kV lines located in Pennsylvania; PECO also owns a 20.7% share of a 500 kV substation immediately outside of the Conemaugh fossil generating station which supplies power to the 500 kV lines noted above.

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

(c) 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 noted above.
(d) Generation has a 44.24% ownership interest in Merrill Creek Reservoir located in New Jersey.

Exelon's, Generation's and PECO'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 and PECO'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 Consolidated Statements of Operations.

7 . Intangible Assets (Exelon, Generation, ComEd and PECO)

Goodwill

Exelon's and ComEd's gross amount of goodwill, accumulated impairment losses and carrying amount of goodwill for the years ended December 31, 2011 and 2010 were as follows:

	2011			2010		
	Gross Amount (a)	Accumulated Impairment Losses	Carrying Amount	Gross Amount (a)	Accumulated Impairment Losses	Carrying Amount
Balance, January 1	$ 4,608	$ 1,983	$ 2,625	$ 4,608	$ 1,983	$ 2,625
Impairment losses	—	—	—	—	—	—
Balance, December 31,	$ 4,608	$ 1,983	$ 2,625	$ 4,608	$ 1,983	$ 2,625

(a) Reflects goodwill recorded in 2000 from the PECO/Unicom 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 might be impaired. The impairment assessment is performed using a two−step, fair value based test. 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. New guidance that does not have an impact on the Step 1 test will become effective for ComEd January 1, 2012. See Note 1—Significant Accounting Policies for additional information on the new guidance. 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, operating and capital expenditure requirements 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.

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

2011 Annual Goodwill Impairment Assessment. The 2011 annual goodwill impairment assessment was performed as of November 1, 2011. 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. Operating and capital expenditure requirements used for the 2011 assessment included the impacts of EIMA discussed in Note 2—Regulatory Matters. Although the fair value of the reporting unit currently exceeds its carrying value, deterioration in market related factors used in the impairment review, a fully successful IRS challenge to Exelon's and ComEd's like−kind exchange income tax position or adverse regulatory actions such as early termination of EIMA could potentially result in a future impairment loss of ComEd's goodwill, which could be material.

Prior Goodwill Impairment Assessments. The 2010 and 2009 annual goodwill impairment assessments were performed as of November 1, 2010 and November 1, 2009, 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.

Other Intangible Assets

Exelon's, Generation's and ComEd's other intangible assets, included in deferred debits and other assets in their Consolidated Balance Sheets, consisted of the following as of December 31, 2011:

	Gross	Accumulated Amortization	Net	Estimated amortization expense 2012	2013	2014	2015	2016
Generation								
Exelon Wind acquisition [(a)]	$ 224	$ (13)	$ 211	$ 13	$ 14	$ 14	$ 14	$ 14
Antelope Valley acquisition [(b)]	190	—	190	—	6	7	7	7
ComEd								
Chicago settlement–1999 agreement [(c)]	100	(69)	31	3	3	3	3	3
Chicago settlement–2003 agreement [(d)]	62	(31)	31	4	4	4	4	4
Total intangible assets	$ 576	$ (113)	$ 463	$ 20	$ 27	$ 28	$ 28	$ 28

(a) Refer to Note 3—Acquisition for additional information regarding Exelon Wind.
(b) Refer to Note 3—Acquisition 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.

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

(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, 2011, 2010 and 2009:

For the Year Ended December 31,	Exelon	Generation	ComEd
2011	$ 19	$ 12	$ 7
2010	8	1	7
2009	7	—	7

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.

Antelope Valley. Upon completion of the development project, all of the output will be sold under a PPA with Pacific Gas & Electric. 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 was recorded in other deferred debits and other assets within Exelon and Generation'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 MRP−based market prices and discount rate. The intangible asset will be amortized as revenue is earned over the 25 term of the underlying PPA. The amortization expense will be reflected as a decrease in operating revenue within Exelon and Generation's Consolidated Statements of Operations and Comprehensive Income.

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. Generation determined that the estimated acquisition−date fair value of the intangible assets was approximately $224 million, which was recorded in other deferred debits and other assets within Exelon and Generation's Consolidated Balance Sheets. Included in this amount is $21 million related to the PPAs for the projects that are in the advanced stage of development. While Generation expects to perform under the PPAs once the construction of these projects is complete, there is a risk of impairment if the projects do not reach commercial operation.

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

Key assumptions used in the valuation of the intangible assets include forecasted power prices and discount rate. The intangible assets will be amortized on a straight−line basis over the period in which the associated contract revenues are recognized. The amortization expense will be reflected as a decrease in operating revenue within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. The weighted−average amortization period for these intangibles is approximately 18 years.

Renewable Energy Credits and Alternative Energy Credits (Exelon, Generation and PECO).

Exelon's, Generation'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 (Exelon and Generation) and AECs (Exelon and PECO). As of December 31, 2011 and 2010, PECO had current AECs of $14 million and $10 million, respectively, and noncurrent AECs of $16 million and $11 million, respectively. As of December 31, 2011 and 2010, the balances of RECs for Generation, which are considered noncurrent, were $6 million and $8 million, respectively. See Notes 2—Regulatory Matters and Note 18—Commitments and Contingencies for additional information on RECs and AECs.

8. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd and PECO)

Non−Derivative Financial Assets and Liabilities. As of December 31, 2011 and 2010, the Registrants' carrying amounts of cash and cash equivalents, accounts receivable, accounts payable, short term notes payable and accrued liabilities are representative of fair value because of the short−term nature of these instruments.

Fair Value of Financial Liabilities Recorded at the Carrying Amount

Exelon

The carrying amounts and fair values of Exelon's long−term debt, SNF obligation and preferred securities of subsidiary as of December 31, 2011 and 2010 were as follows:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long−term debt (including amounts due within one year)	$12,627	$14,488	$12,213	$12,960
Long−term debt to financing trusts	390	358	390	350
Spent nuclear fuel obligation	1,019	886	1,018	876
Preferred securities of subsidiary	87	79	87	68

The fair value of long−term debt is determined using a valuation model, which is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. The fair value of preferred securities of subsidiaries is determined using observable market prices as these securities are actively traded. The carrying amount of Exelon and Generation's SNF obligation resulted from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. Exelon and Generation's obligation to the DOE accrues at the 13−week Treasury rate. When determining the fair value of the obligation, the future carrying amount of the SNF obligation in 2020 is calculated by compounding the current book value of the SNF obligation at the

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

13−week Treasury rate. The future compounded obligation amount is discounted back to present using the prevailing Treasury rate for a long−term obligation with an estimated maturity date of 2020 (after being adjusted for Generation's credit risk).

Generation

The carrying amounts and fair values of Generation's long−term debt and SNF obligation as of December 31, 2011 and 2010 were as follows:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long−term debt (including amounts due within one year)	$ 3,677	$4,231	$ 3,679	$3,792
Spent nuclear fuel obligation	1,019	886	1,018	876

ComEd

The carrying amounts and fair values of ComEd's long−term debt as of December 31, 2011 and 2010 were as follows:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long−term debt (including amounts due within one year)	$ 5,665	$6,540	$ 5,001	$5,411
Long−term debt to financing trust	206	184	206	176

PECO

The carrying amounts and fair values of PECO's long−term debt and preferred securities as of December 31, 2011 and 2010 were as follows:

	2011		2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long−term debt (including amounts due within one year)	$ 1,972	$2,295	$ 2,222	$2,402
Long−term debt to financing trusts	184	174	184	173
Preferred securities	87	79	87	68

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, 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 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 and investments priced using an alternative pricing mechanism.

There were no significant transfers between Level 1 and Level 2 during the years ended December 31, 2011 and 2010. See Note 13—Retirement Benefits for further information regarding the fair value and related valuation techniques for pension and postretirement plan assets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon

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, 2011 and 2010:

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	504	—	—	504
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	774	345	—	1,119
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Corporate debt securities	—	779	—	779
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	774	2,157	—	2,931
Other debt obligations	—	19	13	32
Nuclear decommissioning trust fund investments subtotal [(b)]	2,553	3,998	13	6,564
Pledged assets for Zion decommissioning				
Cash equivalents	—	—	—	—
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	—	311	—	311
Federal agency mortgage−backed securities	—	121	—	121
Commercial mortgage−backed securities (non−agency)	—	10	—	10
Commingled funds	—	20	—	20
Fixed income subtotal	54	553	—	607
Direct lending funds	—	—	37	37
Other debt obligations	—	16	—	16
Pledged assets for Zion decommissioning subtotal[(c)]	89	599	37	725

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

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Rabbi trust investments				
Cash equivalents [d]	2	—	—	2
Mutual funds	—	34	—	34
Rabbi trust investments subtotal	2	34	—	36
Commodity mark−to−market derivative assets				
Cash flow hedges	—	857	—	857
Other derivatives	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Interest rate mark−to−market derivative assets [e]	—	15	—	15
Effect of netting and allocation of collateral	—	(1,827)	(28)	(1,855)
Mark−to−market assets [f]	—	938	144	1,082
Total assets	3,505	5,569	194	9,268
Liabilities				
Commodity mark−to−market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Other derivatives	(1)	(1,137)	(119)	(1,257)
Proprietary trading	—	(236)	(28)	(264)
Interest rate mark−to−market derivative liabilities [e]	—	(19)	—	(19)
Effect of netting and allocation of collateral	—	1,295	20	1,315
Mark−to−market liabilities [f]	(1)	(110)	(127)	(238)
Deferred compensation	—	(73)	—	(73)
Total liabilities	(1)	(183)	(127)	(311)
Total net assets	$3,504	$ 5,386	$ 67	$ 8,957

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$1,473	$ —	$ —	$ 1,473
Nuclear decommissioning trust fund investments				
Cash equivalents	45	—	—	45
Equity				
Equity securities	1,513	—	—	1,513
Commingled funds	—	2,081	—	2,081
Equity funds subtotal	1,513	2,081	—	3,594
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	504	96	—	600
Debt securities issued by states of the United States and political subdivisions of the states	—	451	—	451
Corporate debt securities	—	619	—	619
Federal agency mortgage−backed securities	—	804	—	804
Commercial mortgage−backed securities (non−agency)	—	114	—	114
Residential mortgage−backed securities (non−agency)	—	14	—	14
Commingled funds	—	47	—	47
Mutual funds	—	40	—	40
Fixed income subtotal	504	2,185	—	2,689
Other debt obligations	—	48	—	48
Nuclear decommissioning trust fund investments subtotal [b]	2,062	4,314	—	6,376

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

Table of Contents

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Pledged assets for Zion decommissioning				
Equity				
Equity securities	84	—	—	84
Commingled funds	—	82	—	82
Equity funds subtotal	84	82	—	166
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	166	12	—	178
Debt securities issued by states of the United States and political subdivisions of the states	—	45	—	45
Corporate debt securities	—	263	—	263
Federal agency mortgage−backed securities	—	102	—	102
Commercial mortgage−backed securities (non−agency)	—	14	—	14
Commingled funds	—	50	—	50
Fixed income subtotal	166	486	—	652
Other debt obligations	—	2	—	2
Pledged assets for Zion decommissioning subtotal [c]	250	570	—	820
Rabbi trust investments				
Mutual funds [d]	—	36	—	36
Rabbi trust investments subtotal	—	36	—	36
Mark−to−market derivative assets				
Cash flow hedges	—	724	12	736
Other derivatives	2	1,709	57	1,768
Proprietary trading	—	235	46	281
Effect of netting and allocation of collateral [e]	(3)	(1,848)	(38)	(1,889)
Mark−to−market assets [f]	(1)	820	77	896
Total assets	3,784	5,740	77	9,601
Liabilities				
Mark−to−market derivative liabilities				
Cash flow hedges	—	(45)	—	(45)
Other derivatives	(2)	(667)	(29)	(698)
Proprietary trading	—	(233)	(21)	(254)
Effect of netting and allocation of collateral [e]	1	914	23	938
Mark−to−market liabilities [f]	(1)	(31)	(27)	(59)
Deferred compensation	—	(76)	—	(76)
Total liabilities	(1)	(107)	(27)	(135)
Total net assets	$3,783	$ 5,633	$ 50	$ 9,466

(a) Excludes certain cash equivalents considered to be held−to−maturity and not reported at fair value.
(b) Excludes net (liabilities) assets of $(57) million and $32 million at December 31, 2011 and 2010, 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 $9 million and $4 million at December 31, 2011 and 2010. These items consist of receivables related to pending securities sales, interest and dividend receivables and payables related to pending securities purchases.
(d) Excludes $25 million of the cash surrender value of life insurance investments at December 31, 2011 and 2010.
(e) Includes collateral postings received from counterparties. 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,

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

as of December 31, 2011. Collateral received from counterparties, net of collateral paid to counterparties, totaled $2 million, $934 million and $15 million allocated to Level 1, Level 2 and Level 3 mark−to−market derivatives, respectively, as of December 31, 2010.

(f) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $503 million and $191 million at December 31, 2011 and $450 million and $525 million at December 31, 2010, respectively, related to the fair value of Generation's financial swap contract with ComEd; and current assets of $5 million at December 31, 2010, related to the fair value of Generation's block contracts with PECO, which eliminate upon consolidation in Exelon's Consolidated Financial Statements. Generation's block contracts with PECO ended December 31, 2011.

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, 2011 and 2010:

For the Year Ended December 31, 2011	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Mark−to−Market Derivatives	Total
Balance as of January 1, 2011	$ —	$ —	$ 50	$ 50
Total realized / unrealized gains (losses)				
Included in income	1	—	99[(a)]	100
Included in other comprehensive income	—	—	(25)[(b)]	(25)
Included in regulatory liabilities	2	—	(106)	(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 related to assets and liabilities held for the year ended December 31, 2011	$ 1	$ —	$ 131	$ 132

(a) Includes the reclassification of $32 million of realized losses due to settlements 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 reclassified from OCI due to settlements of associated with Generation's financial swap contract with ComEd for the year ended December 31, 2011 and $5 million of decreases in fair value due to settlement of Generation's block contracts with PECO for the year ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2010	Servicing Liability	Nuclear Decommissioning Trust Fund Investments	Mark−to−Market Derivatives	Total
Balance as of January 1, 2010	$ (2)	$ —	$ (44)	$(46)
Total realized / unrealized gains				
Included in income	2[(c)]	—	46[(a)]	48
Included in other comprehensive income	—	—	16[(b)]	16
Included in regulatory assets/liabilities	—	—	2	2
Change in collateral	—	—	(10)	(10)
Purchases, sales, issuances and settlements				
Purchases	—	13	15	28
Sales	—	(1)	—	(1)
Transfers out of Level 3	—	(12)	25	13
Balance as of December 31, 2010	$ —	$ —	$ 50	$ 50
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the year ended December 31, 2010	$ —	$ —	$ 54	$ 54

(a) Includes the reclassification of $8 million of realized losses due to settlements of derivative contracts recorded in results of operations.
(b) Excludes increases in fair value of $375 million and realized losses reclassified from OCI due to settlements of $371 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in the fair value of the block contracts with PECO after that point, as the mark−to−market balances previously recorded will be amortized over the term of the contracts. The increase in fair value was $3 million through May 31, 2010. Generation's block contracts with PECO ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.
(c) The servicing liability related to PECO's accounts receivable agreement was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.

The following table presents 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, 2011 and 2010:

	Operating Revenue	Purchased Power	Fuel	Other, net (a)
Total gains (losses) included in income for the year ended December 31, 2011	$ 108	$ —	$ (9)	$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2011	$ 137	$ —	$ (6)	$ 1

	Operating Revenue	Purchased Power	Fuel	Other, net
Total gains included in income for the year ended December 31, 2010	$ 3	$ 7	$ 36	$ —
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2010	$ 22	$ 4	$ 28	$ —

(a) Other, net activity consists of realized and unrealized gains included in income for the NDT funds held by Generation.

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

Generation

The following table presents assets and liabilities measured and recorded at fair value on Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2011 and 2010:

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents[a]	$ 466	$ —	$ —	$ 466
Nuclear decommissioning trust fund investments				
Cash equivalents	504	—	—	504
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	774	345	—	1,119
Debt securities issued by states of the United States and political subdivisions of the states	—	541	—	541
Corporate debt securities	—	779	—	779
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	774	2,157	—	2,931
Other debt obligations	—	19	13	32
Nuclear decommissioning trust fund investments subtotal[b]	2,553	3,998	13	6,564
Pledged assets for Zion Station 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	—	311	—	311
Federal agency mortgage−backed securities	—	121	—	121
Commercial mortgage−backed securities (non−agency)	—	10	—	10
Commingled funds	—	20		20
Fixed income subtotal	54	553	—	607
Direct lending funds	—	—	37	37
Other debt obligations	—	16	—	16
Pledged assets for Zion Station decommissioning subtotal[c]	89	599	37	725
Rabbi trust investments[d][e]	—	4	—	4

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Commodity mark−to−market derivative assets				
Cash flow hedges	—	857	694	1,551
Other derivatives	—	1,653	124	1,777
Proprietary trading	—	240	48	288
Effect of netting and allocation of collateral [f]	—	(1,827)	(28)	(1,855)
Mark−to−market assets [g]	—	923	838	1,761
Total assets	3,108	5,524	888	9,520
Liabilities				
Commodity mark−to−market derivative liabilities				
Cash flow hedges	—	(13)	—	(13)
Other derivatives	(1)	(1,137)	(13)	(1,151)
Proprietary trading	—	(236)	(28)	(264)
Interest rate mark−to−market derivative liabilities	—	(19)	—	(19)
Effect of netting and allocation of collateral [f]	—	1,295	20	1,315
Mark−to−market liabilities	(1)	(110)	(21)	(132)
Deferred compensation	—	(18)	—	(18)
Total liabilities	(1)	(128)	(21)	(150)
Total net assets	$3,107	$ 5,396	$ 867	$ 9,370

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 419	$ —	$ —	$ 419
Nuclear decommissioning trust fund investments				
Cash equivalents	45	—	—	45
Equity				
Equity securities	1,513	—	—	1,513
Commingled funds	—	2,081	—	2,081
Equity funds subtotal	1,513	2,081	—	3,594
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	504	96	—	600
Debt securities issued by states of the United States and political subdivisions of the states	—	451	—	451
Corporate debt securities	—	619	—	619
Federal agency mortgage−backed securities	—	804	—	804
Commercial mortgage−backed securities (non−agency)	—	114	—	114
Residential mortgage−backed securities (non−agency)	—	14	—	14
Commingled funds	—	47	—	47
Mutual funds	—	40	—	40
Fixed income subtotal	504	2,185	—	2,689
Other debt obligations	—	48	—	48
Nuclear decommissioning trust fund investments subtotal [b]	2,062	4,314	—	6,376

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

Table of Contents

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Pledged assets for Zion Station decommissioning				
Equity				
Equity securities	84	—	—	84
Commingled funds	—	82	—	82
Equity funds subtotal	84	82	—	166
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	166	12	—	178
Debt securities issued by states of the United States and political subdivisions of the states	—	45	—	45
Corporate debt securities	—	263	—	263
Federal agency mortgage−backed securities	—	102	—	102
Commercial mortgage−backed securities (non−agency)	—	14	—	14
Residential mortgage−backed securities (non−agency)	—	—	—	—
Commingled funds	—	50	—	50
Fixed income subtotal	166	486	—	652
Other debt obligations	—	2	—	2
Pledged assets for Zion Station decommissioning subtotal [c]	250	570	—	820
Rabbi trust investments [d][e]	—	4	—	4
Mark−to−market derivative assets				
Cash flow hedges	—	724	992	1,716
Other derivatives	2	1,695	53	1,750
Proprietary trading	—	235	46	281
Effect of netting and allocation of collateral [f]	(3)	(1,848)	(38)	(1,889)
Mark−to−market derivative net assets [g]	(1)	806	1,053	1,858
Total assets	2,730	5,694	1,053	9,477
Liabilities				
Mark−to−market derivative liabilities				
Cash flow hedges	—	(45)	—	(45)
Other derivatives	(2)	(667)	(25)	(694)
Proprietary trading	—	(233)	(21)	(254)
Effect of netting and allocation of collateral [f]	1	914	23	938
Mark−to−market liabilities	(1)	(31)	(23)	(55)
Deferred compensation	—	(20)	—	(20)
Total liabilities	(1)	(51)	(23)	(75)
Total net assets	$2,729	$ 5,643	$1,030	$ 9,402

(a) Excludes certain cash equivalents considered to be held−to−maturity and not reported at fair value.
(b) Excludes net (liabilities) assets of $(57) million and $32 million at December 31, 2011 and 2010, 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 $9 million and $4 million at December 31, 2011 and 2010, 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 that are invested in common stock of Standard and Poor’s 500 companies and Pennsylvania municipal bonds are primarily rated as investment grade.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(e) Excludes $7 million of the cash surrender value of life insurance investments at December 31, 2011 and 2010.
(f) Includes collateral postings received from counterparties. 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. Collateral received from counterparties, net of collateral paid to counterparties, totaled $2 million, $934 million and $15 million allocated to Level 1, Level 2 and Level 3 mark−to−market derivatives, respectively, as of December 31, 2010.
(g) The Level 3 balance includes current and noncurrent assets for Generation of $503 million and $191 million at December 31, 2011 and $450 million and $525 million at December 31, 2010, respectively, related to the fair value of Generation's financial swap contract with ComEd; and current assets of $5 million at December 31, 2010 related to the fair value of Generation's block contracts with PECO. All of the mark−to−market balances Generation carries associated with the financial swap contract with ComEd and the block contracts with PECO eliminate upon consolidation in Exelon's Consolidated Financial Statements. Generation's block contracts with PECO ended December 31, 2011.

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, 2011 and 2010:

Year Ended December 31, 2011	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark−to−Market Derivatives	Total
Balance as of January 1, 2011	$ —	—	$ 1,030	$1,030
Total unrealized / realized gains (losses)				
Included in income	1	—	99[(a)]	100
Included in other comprehensive income	—	—	(311)[(b)]	(311)
Included in noncurrent payables to affiliates	2	—	—	2
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	$ 817	$ 867
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the year ended 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) Includes $170 million of increases in fair value and $451 million of realized losses reclassified from OCI due to settlements associated with Generation's financial swap contract with ComEd for the year ended December 31, 2011, and $5 million of decreases in fair value due to settlement of Generation's block contracts with PECO for the year ended December 31, 2011. Generation's block contracts with PECO ended December 31, 2011. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

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

Year Ended December 31, 2010	Nuclear Decommissioning Trust Fund Investments	Mark−to−Market Derivatives	Total
Balance as of January 1, 2010	$ —	$ 931	$ 931
Total unrealized / realized gains:			
Included in income	—	46[(a)]	46
Included in other comprehensive income	—	23[(b)]	23
Change in collateral	—	(10)	(10)
Purchases, sales, issuances and settlements:			
Purchases	13	15	28
Sales	(1)	—	(1)
Transfers out of Level 3	(12)	25	13
Balance as of December 31, 2010	$ —	$ 1,030	$1,030
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the year ended December 31, 2010	$ —	$ 54	$ 54

(a) Includes the reclassification of $8 million of realized losses due to settlements of derivative contracts recorded in results of operations.
(b) Includes increases in fair value of $375 million and realized losses reclassified from OCI due to settlements of $371 million associated with Generation's financial swap contract with ComEd for the year ended December 31, 2010. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in fair value of the block contracts with PECO after that point, as the mark−to−market balances previously recorded will be amortized over the term of the contracts. The increase in fair value was $3 million through May 31, 2010. All items eliminate upon consolidation in Exelon's Consolidated Financial Statements.

The following table presents 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, 2011 and 2010:

	Operating Revenue	Purchased Power	Fuel	Other, net (a)
Total gains (losses) included in income for the year ended December 31, 2011	$ 108	$ —	$ (9)	$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held for the year ended December 31, 2011	$ 137	$ —	$ (6)	$ 1

	Operating Revenue	Purchased Power	Fuel	Other, net
Total gains included in income for the year ended December 31, 2010	$ 3	$ 7	$ 36	$ —
Change in the unrealized gains relating to assets and liabilities held for the year ended December 31, 2010	$ 22	$ 4	$ 28	$ —

(a) Other, net activity consists of realized and unrealized gains included in income for the NDT funds held by Generation.

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

ComEd

The following table presents assets measured and recorded at fair value on ComEd's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2011 and 2010:

As of December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 173	$ —	$ —	$ 173
Rabbi trust investments				
Cash equivalents	2	—	—	2
Mutual funds	—	19	—	19
Rabbi trust investments subtotal	2	19	—	21
Total assets	175	19	—	194
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark−to−market derivative liabilities [(b)(c)]	—	—	(800)	(800)
Total liabilities	—	(8)	(800)	(808)
Total net assets (liabilities)	$ 175	$ 11	$ (800)	$(614)

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 1	$ —	$ —	$ 1
Rabbi trust investments				
Mutual Funds	—	23	—	23
Rabbi trust investments subtotal	—	23	—	23
Mark−to−market derivative assets [(c)]	—	—	4	4
Total assets	1	23	4	28
Liabilities				
Deferred compensation obligation	—	(8)	—	(8)
Mark−to−market derivative liabilities [(b)]	—	—	(975)	(975)
Total liabilities	—	(8)	(975)	(983)
Total net assets (liabilities)	$ 1	$ 15	$ (971)	$(955)

(a) Excludes certain cash equivalents considered to be held−to−maturity and not reported at fair value.
(b) The Level 3 balance includes a current and noncurrent liability of $503 million and $191 million at December 31, 2011, respectively, and $450 million and $525 million at December 31, 2010, respectively, related to the fair value of ComEd's financial swap contract with Generation which eliminates upon consolidation in Exelon's Consolidated Financial Statements.
(c) The Level 3 balance includes a current and noncurrent liability of $9 million and $97 million at December 31, 2011, respectively, and a noncurrent asset of $4 million at December 31, 2010 related to floating−to−fixed energy swap contracts with unaffiliated suppliers.

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

Table of Contents

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, 2011 and 2010:

For the Year Ended December 31, 2011	Mark−to−Market Derivatives
Balance as of January 1, 2011	$ (971)
Total realized / unrealized gains / (losses) included in regulatory assets [(a)(b)]	171
Balance as of December 31, 2011	$ (800)

(a) Includes decreases in fair value of $170 million and realized gains due to settlements of $451 million associated with ComEd's financial swap contract with Generation. All items eliminated upon consolidated in Exelon's Consolidated Financial Statements.
(b) Includes a decrease in fair value of $110 million associated with floating−to−fixed energy swap contracts with unaffiliated suppliers.

For the Year Ended December 31, 2010	Mark−to−Market Derivatives
Balance as of January 1, 2010	$ (971)
Total realized / unrealized gains / (losses) included in regulatory assets [(a)(b)]	—
Balance as of December 31, 2010	$ (971)

(a) Includes decreases in fair value of $375 million and realized gains due to settlements of $371 million associated with ComEd's financial swap contract with Generation. All items eliminated upon consolidation in Exelon's Consolidated Financial Statements.
(b) Includes an increase in fair value of $4 million associated with floating−to−fixed energy swap contracts with unaffiliated suppliers.

PECO

The following table presents assets and liabilities measured and recorded at fair value on PECO's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2011 and 2010:

December 31, 2011	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [(a)]	$ 175	$ —	$ —	$ 175
Rabbi trust investments—mutual funds [(b)]	—	9	—	9
Total assets	175	9	—	184
Liabilities				
Deferred compensation obligation	—	(21)	—	(21)
Current mark−to−market derivative liabilities [(c)]	—	—	—	—
Total liabilities	—	(21)	—	(21)
Total net assets (liabilities)	$ 175	$ (12)	$ —	$ 163

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

As of December 31, 2010	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents [a]	$ 499	$ —	$ —	$499
Rabbi trust investments—mutual funds [b]	—	7	—	7
Total assets	499	7	—	506
Liabilities				
Deferred compensation obligation	—	(23)	—	(23)
Noncurrent mark−to−market derivative liabilities [c]	—	—	(9)	(9)
Total liabilities	—	(23)	(9)	(32)
Total net assets (liabilities)	$ 499	$ (16)	$ (9)	$474

(a) Excludes certain cash equivalents considered to be held−to−maturity and not reported at fair value.
(b) Excludes $13 million of the cash surrender value of life insurance investments at December 31, 2011 and 2010.
(c) The Level 3 balances include a current liability of $5 million at the December 31, 2010, related to the fair value of PECO's block contracts with Generation that eliminate upon consolidation in Exelon's Consolidated Financial Statements. Generation's block contracts with PECO expired on December 31, 2011.

The following tables present the fair value reconciliation of Level 3 assets measured at fair value on a recurring basis during the years ended December 31, 2011 and 2010:

For the Year Ended December 31, 2011	Mark−to−Market Derivatives
Balance as of January 1, 2011	$ (9)
Total realized/unrealized gains included in regulatory assets [a]	9
Balance as of December 31, 2011	$ —

(a) Includes an increase of $5 million related to the settlement of PECO's block contracts with Generation, which eliminates upon consolidation in Exelon's Consolidated Financial Statements. Generation's block contracts with PECO expired on December 31, 2011.

For the Year Ended December 31, 2010	Mark−to−Market Derivatives	Servicing Liability	Total
Balance as of January 1, 2010	$ (4)	$ (2)	$ (6)
Total realized/unrealized gains (losses):			
Included in net income	—	2[a]	2
Included in regulatory assets	(5)[b]	—	(5)
Balance as of December 31, 2010	$ (9)	$ —	$ (9)

(a) The servicing liability related to PECO's accounts receivable agreement was released in accordance with new authoritative guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.
(b) Includes a decrease in fair value of $3 million associated with PECO's block contract with Generation, which eliminates upon consolidation in Exelon's Consolidated Financial Statements.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd and PECO). The Registrants' 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 (Exelon and Generation). The trust fund investments have been established to satisfy Exelon's and 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. See Note 12—Nuclear Decommissioning for further discussion on the NDT fund investments.

Direct lending funds are investments in managed funds which invest in private companies for long−term capital appreciation. The fair value of these securities is determined using either an enterprise value model or a bond valuation model. Investments in direct lending funds 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.

Rabbi Trust Investments (Exelon, Generation, ComEd and PECO). 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 the Registrants' 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 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 commingled 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 (Exelon, Generation, ComEd and PECO). 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 are valued using indicative price quotations available through brokers or over−the−counter, on−line exchanges and are categorized in Level 2. These price quotations reflect the average of the bid−ask, mid−point prices and are obtained from sources that the Registrants believe provide the most liquid market for the commodity. The price quotations are reviewed and corroborated to ensure the prices are observable and representative of an orderly transaction between market participants. This includes consideration of actual transaction volumes, market delivery points, bid−ask spreads and contract duration. The remainder of 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. The Registrants' 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. 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. 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. 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 beginning of the month 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 and out of Level 2 and Level 3, respectively, generally occur when the contract tenure becomes more observable.

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, the Registrants 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. 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 9—Derivative Financial Instruments for further discussion on mark−to−market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd and PECO). The Registrants' deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants' deferred compensation obligations is based on the market value of the participants' notional investment accounts. The 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.

Servicing Liability (Exelon and PECO). PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in customer accounts receivables designated under the agreement in exchange for proceeds of $225 million, which PECO accounted for as a sale under previous guidance on accounting for transfers of financial assets. A servicing liability was recorded for the agreement in accordance with the applicable authoritative guidance for servicing of financial assets. The servicing liability was included in other current liabilities in Exelon's and PECO's Consolidated Balance Sheets. The fair value of the liability was determined using internal estimates based on provisions in the agreement, which were categorized as Level 3 inputs in the fair value hierarchy. The servicing liability was released in accordance with new guidance on accounting for transfers of financial assets that was adopted on January 1, 2010. See Note 10—Debt and Credit Agreements for additional information.

9. Derivative Financial Instruments (Exelon, Generation, ComEd and PECO)

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative financial instruments are commodity price risk and interest rate risk. To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market price fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their 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. The Registrants believe these instruments, which are classified as either economic hedges or non−derivatives, mitigate exposure to fluctuations in commodity prices. Exposure to interest rate risk exists as a result of the issuance of variable and fixed−rate debt, commercial paper and lines of credit.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value. Under these provisions, economic hedges are recognized on the balance sheet at their fair value unless they qualify for the normal purchases and normal sales exception. The Registrants have applied the normal purchases and normal sales scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. For economic hedges that qualify and are designated as cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in value of the underlying exposure is deferred in accumulated OCI and later reclassified into earnings when the underlying transaction occurs. For economic hedges that do not qualify or are not designated as cash flow hedges, changes in the fair value of the derivative are recognized in earnings each period and are classified as other derivatives in the following tables. Non−derivative contracts for access to additional generation and for sales to load−serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 18—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.

Commodity Price Risk (Exelon, Generation, ComEd and PECO)

Economic Hedging. The Registrants are 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, 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 financial transmission rights, whose changes in fair value are recognized in earnings each period, and auction revenue rights.

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 risk on a ratable basis over three−year periods. As of December 31, 2011, the percentage of expected generation hedged was 88%−91%, 61%−64%, and 32%−35% for 2012, 2013 and 2014, 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 cash flow hedges, other derivatives and certain non−derivative contracts, including sales to ComEd and PECO 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 is further discussed in Note 2—Regulatory Matters, qualify for the normal purchases and normal sales scope 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 has been designated by Generation as a cash flow hedge. Consequently, Generation records the fair value of the swap on its balance sheet and records changes in fair value to OCI. 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 2—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 begins 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 Program, which is further discussed in Note 2—Regulatory Matters. Based on Pennsylvania legislation and the DSP Program 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 Sheets 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 2011 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 2011 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 covers 22% to 29% 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.

Proprietary Trading. Generation also enters into certain energy−related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into purely to profit from market price changes as opposed to hedging an exposure and is subject to limits established by Exelon's RMC. The proprietary trading activities, which included physical volumes of 5,742 GWh, 3,625 GWh and 7,578 GWh for years ended December 31, 2011, 2010 and 2009, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's revenue from energy marketing activities. Neither ComEd nor PECO enter into derivatives for proprietary trading purposes.

Interest Rate Risk (Exelon, Generation and ComEd)

The Registrants use a combination of fixed−rate and variable−rate debt to manage interest rate exposure. The Registrants 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 Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. A hypothetical 10% increase in the interest rates associated with variable−rate debt would result in less than a $1 million decrease in Exelon's, Generation's, and ComEd's pre−tax income for the year ended December 31, 2011.

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

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 December 31,			Gain (Loss) on Borrowings December 31,		
Income Statement Classification	2011	2010	2009	2011	2010	2009
Interest expense	$ 1	$ 4	$ (7)	$ (1)	$ (4)	$ 7

At December 31, 2011 and 2010, Exelon had $100 million of notional amounts of fair value hedges outstanding related to interest rate swaps, with fair value assets of $15 million and $14 million, respectively. During the years ended December 31, 2011 and 2010, there was no impact on the results of operations as a result of ineffectiveness from fair value hedges.

Cash Flow Hedges. In connection with the DOE guaranteed loan for the Antelope Valley acquisition, as discussed in Note 10–Debt and Credit Agreements, Generation entered into a floating−to−fixed interest rate swap with a notional amount of $485 million, which hedges approximately 75% of Generation's future interest rate exposure associated with the financing. The swap was designated as a cash flow hedge, as Generation has determined that the DOE loan remains probable to occur. As such, the effective portion of the hedge will be recorded in other comprehensive income within Generation's Consolidated Balance Sheets, with any ineffectiveness recorded in Generation's Consolidated Statements of Operations and Comprehensive Income. 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 will be reflected in earnings through the remaining term of the hedge. In order to mitigate this earnings impact, a series of offsetting hedge transactions will be executed as Generation draws on the loan. At December 31, 2011, Generation had a $19 million mark−to−market non−current derivative liability relating to the interest rate swap in connection with the loan agreement to fund Antelope Valley as discussed above.

On September 30, 2010, Generation issued and sold $350 million of senior notes due October 1, 2041. In connection with this debt issuance, Generation entered into treasury rate locks in the aggregate notional amount of $240 million. The treasury rate locks were settled on September 27, 2010. Treasury rate locks were derivative instruments used to lock in the interest rate prior to the issuance of debt. As a result of a decrease in interest rates during the period between the inception and settlement of the treasury rate locks, Generation recorded a pre−tax loss of approximately $4 million. The loss was recorded to other comprehensive income within Generation's Consolidated Balance Sheets and is being amortized as an increase to interest expense over the life of the related debt as interest payments are made on the debt.

In connection with its August 2, 2010 issuance of First Mortgage Bonds, ComEd entered into treasury rate locks in the aggregate notional amount of $350 million. The treasury rate locks were settled on July 27, 2010. As interest rates decreased since the inception of the treasury rate locks, ComEd recorded a pre−tax loss of approximately $4 million. Under the authoritative accounting guidance for regulated operations, the loss was recorded as a regulatory asset within ComEd's Consolidated Balance Sheets at settlement and is being amortized as an increase to interest expense over the life of the related debt as interest payments are made on the debt.

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

Fair Value Measurement (Exelon, Generation, ComEd and PECO)

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 commodity cash flow hedges, other derivatives 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 normal purchases and normal sales 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, 2011:

	Generation					ComEd	PECO	Other		Exelon
Derivatives	Cash Flow Hedges [a]	Other Derivatives	Proprietary Trading	Collateral and Netting [b]	Subtotal [c]	Other Derivatives [a][d]	Other Derivatives	Other Derivatives	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 liabilities with affiliate (current liabilities)	—	—	—	—	—	(503)	—	—	503	—
Mark−to−market derivative liabilities (noncurrent liabilities)	(4)	(186)	(70)	250	(10)	(97)	—	—	—	(107)
Mark−to−market derivative liabilities 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

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

(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 noncurrent 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.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2010:

	Generation					ComEd	PECO	Other		Exelon
Derivatives	Cash Flow Hedges (a)	Other Derivatives	Proprietary Trading	Collateral and Netting (b)	Subtotal (c)	Other Derivatives (a)(e)	Other Derivatives (d)	Other Derivatives	Intercompany Eliminations (a)(d)	Total Derivatives
Mark−to−market derivative assets (current assets)	$ 532	$ 1,203	$ 225	$ (1,473)	$ 487	$ —	$ —	$ —	$ —	$ 487
Mark−to−market derivative assets with affiliate (current assets)	455	—	—	—	455	—	—	—	(455)	—
Mark−to−market derivative assets (noncurrent assets)	204	547	56	(416)	391	4	—	14	—	409
Mark−to−market derivative assets with affiliate (noncurrent assets)	525	—	—	—	525	—	—	—	(525)	—
Total mark−to−market derivative assets	$ 1,716	$ 1,750	$ 281	$ (1,889)	$ 1,858	$ 4	$ —	$ 14	$ (980)	$ 896
Mark−to−market derivative liabilities (current liabilities)	$ (21)	$ (551)	$ (200)	$ 738	$ (34)	$ —	$ (4)	$ —	$ —	$ (38)
Mark−to−market derivative liabilities with affiliate (current liabilities)	—	—	—	—	—	(450)	(5)	—	455	—
Mark−to−market derivative liabilities (noncurrent liabilities)	(24)	(143)	(54)	200	(21)	—	—	—	—	(21)
Mark−to−market derivative liabilities with affiliate (noncurrent liabilities)	—	—	—	—	—	(525)	—	—	525	—
Total mark−to−market derivative liabilities	$ (45)	$ (694)	$ (254)	$ 938	$ (55)	$ (975)	$ (9)	$ —	$ 980	$ (59)
Total mark−to−market derivative net assets (liabilities)	$ 1,671	$ 1,056	$ 27	$ (951)	$ 1,803	$ (971)	$ (9)	$ 14	$ —	$ 837

(a) Includes current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $450 million and $525 million, respectively, related to the fair value of the five−year financial swap contract between Generation and ComEd, as described 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 $725 million and $199 million, respectively, and current and noncurrent liabilities are shown inclusive of collateral of $10 million and $17 million, respectively. The total cash collateral received net of cash collateral posted and offset against mark−to−market assets and liabilities was $951 million at December 31, 2010.
(d) Includes current assets for Generation and current liabilities for PECO of $5 million related to the fair value of PECO's block contracts with Generation. There were no netting adjustments or collateral received as of December 31, 2010. The PECO block contracts were designated as normal purchases in May 2010. As such, no additional changes in the fair value of PECO's block contracts were recorded and the mark−to−market balances previously recorded were amortized over the terms of the contracts, which ended December 31, 2011.
(e) Includes noncurrent assets related to floating−to−fixed energy swap contracts with unaffiliated suppliers.

Cash Flow Hedges (Exelon, Generation and ComEd). Economic hedges that qualify as cash flow hedges primarily consist of forward power sales and power swaps on base load generation. At December 31, 2011, Generation had net unrealized pre−tax gains on effective cash flow hedges of $1,529 million being deferred within accumulated OCI, including $694 million related to the financial swap with ComEd. Amounts recorded in accumulated OCI related to changes in energy commodity cash flow hedges are reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs. Reclassifications from OCI are included in operating revenues, purchased power and fuel in Exelon's and Generation's Consolidated Statements of Operations, depending on the commodities involved in the hedged transaction. Based on market prices at December 31, 2011, approximately $925 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 $503 million related to the financial swap with ComEd. However, the actual amount reclassified from accumulated OCI could vary due to future changes in market prices. Generation expects the settlement of the majority of its cash flow hedges, including the ComEd financial swap contract, will occur during 2012 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, 2011 and 2010, amounts reclassified into earnings as a result of the discontinuance of cash flow hedges were immaterial.

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

Table of Contents

The table below provides the activity of accumulated OCI related to cash flow hedges for the years ended December 31, 2011 and 2010, 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, 2010		$ 1,152(a)(d)	$ 551
Effective portion of changes in fair value		541(b)	304(e)
Reclassifications from accumulated OCI to net income	Operating Revenues	(681)(c)	(454)(f)
Ineffective portion recognized in income	Purchased Power	(1)	(1)
Accumulated OCI derivative gain at December 31, 2010		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	Operating Revenues	(5)	(5)
Accumulated OCI derivative gain at December 31, 2011		$ 925(a)(d)	$ 488

(a) Includes $420 million, $589 million and $585 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, 2011, 2010 and 2009, 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 $104 million and $228 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, 2011 and 2010, 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. The PECO block contracts were designated as normal sales as of May 31, 2010. As such, there were no effective changes in fair value of the block contracts with PECO in 2011 or for the remainder of 2010 as the mark−to−market balances previously recorded were amortized over the terms of the contracts.

(c) Includes $273 million and $224 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, 2011 and 2010, 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 $10 million of losses and $2 million of gains, net of taxes, related to interest rate swaps and treasury rate locks for the years ended December 31, 2011 and 2010, respectively. Excludes $5 million of gains, net of taxes, related to interest rate swaps for the year ended December 31, 2009. See Note 10—Debt and Credit Agreements for further information.

(e) Includes $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, 2011. Includes $6 million of losses, net of taxes, related to the effective portion of changes in fair value of treasury rate locks at Generation and ComEd for the year ended December 31, 2010.

(f) Reflects the reclassifications of $4 million to regulatory assets and $1 million to deferred income tax liabilities within Exelon's and ComEd's Consolidated Balance Sheets associated with settled treasury rate locks at ComEd.

During the years ended December 31, 2011, 2010 and 2009, Generation's cash flow hedge activity impact to pre−tax earnings, based on the reclassification adjustment from accumulated OCI to earnings, was a pre−tax gain of $968 million, $1,125 million and $1,559 million, respectively. Given that the cash flow hedges primarily consist of forward power sales and power swaps and do not include gas options or sales, the ineffectiveness of Generation's cash flow hedges is primarily the result of differences between the locational settlement prices of the cash flow hedges and the hedged generating units. This price difference is 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 increases of $9 million and $1 million, and a decrease of $15 million for the years ended December 31, 2011, 2010 and 2009, respectively, none of which was related to Generation's financial swap contract with ComEd or Generation's block contracts with PECO. Cash flow hedge ineffectiveness resulted in an decrease of $10 million and $1 million related to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses at December 31, 2011 and 2010, respectively.

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

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 pre−tax gain of $512 million, $754 million and $1,292 million for the years ended December 31, 2011, 2010 and 2009, respectively. Changes in cash flow hedge ineffectiveness, primarily due to changes in market prices, were increases of $9 million, $1 million, and a decrease of $15 million for the years ended December 31, 2011, 2010 and 2009, respectively. Cash flow hedge ineffectiveness resulted in an decrease of $10 million and $1 million to accumulated OCI on the balance sheet in order to reflect the effective portion of derivative gains or losses at December 31, 2011 and 2010, respectively.

Other Derivatives (Exelon and Generation). Other derivative contracts are those that do not qualify or are not designated for hedge accounting. These instruments represent economic hedges that mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps and forward sales. For the years ended December 31, 2011, 2010 and 2009, the following net pre−tax mark−to−market gains (losses) of certain sale and purchase contracts were reported in operating revenues and fuel and purchased power expense at Exelon and Generation in the Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. 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.

	Exelon and Generation			
For the Year Ended December 31, 2011	Operating Revenues	Purchased Power	Fuel	Total
Change in fair value	$ 87	$ 17	$ 114	$ 218
Reclassification to realized at settlement	(296)	(31)	(188)	(515)
Net mark−to−market gains (losses) [(a)]	$ (209)	$ (14)	$ (74)	$(297)

	Exelon and Generation			
For the Year Ended December 31, 2010	Operating Revenues	Purchased Power	Fuel	Total
Change in fair value	$ —	$ 288	$ 101	$ 389
Reclassification to realized at settlement	—	(292)	(12)	(304)
Net mark−to−market gains (losses)	$ —	$ (4)	$ 89	$ 85

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2009	Exelon and Generation Operating Revenues	Purchased Power	Fuel	Total
Change in fair value	$ —	$ 206	$ (72)	$134
Reclassification to realized at settlement	—	(97)	159	62
Net mark−to−market gains	$ —	$ 109	$ 87	$196

(a) Exelon and Generation have historically presented mark−to−market gains and losses within purchased power expense for all non−trading, power−related derivatives that were not accounted for as cash flow hedges. In 2011, Exelon and Generation classified the mark−to−market gains and losses for contracts, where the underlying hedged transaction was an expected sale, to operating revenues. In prior years, this treatment was not material to reported operating revenues and purchased power expense. As a result, prior year amounts have not been reclassified.

Proprietary Trading Activities (Exelon and Generation). For the years ended December 31, 2011, 2010 and 2009, Exelon and Generation 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 and Generation's Consolidated Statements of Operations and Comprehensive Income and are included in "Net fair value changes related to derivatives" in Exelon's and Generation's Consolidated Statements of Cash Flows. 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, 2011	2010	2009
Change in fair value	Operating Revenues	$ 23	$ 26	$ 3
Reclassification to realized at settlement	Operating Revenues	(26)	(24)	(86)
Net mark−to−market gains (losses)	Operating Revenues	$ (3)	$ 2	$(83)

Credit Risk (Exelon, Generation, ComEd and PECO)

The Registrants 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 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.

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

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase and normal sales, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of December 31, 2011. 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 maturity 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 RTOs, ISOs, NYMEX and ICE commodity exchanges, further discussed in ITEM 3—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 and PECO of $70 million and $39 million, respectively. See Note 21—Related Party Transactions for further information.

Rating as of December 31, 2011	Total Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,581	$ 351	$ 1,230	1	$ 179
Non−investment grade	5	2	3	—	—
No external ratings					
Internally rated—investment grade	63	14	49	—	—
Internally rated—non−investment grade	1	—	1	—	—
Total	$ 1,650	$ 367	$ 1,283	1	$ 179

Net Credit Exposure by Type of Counterparty	December 31, 2011
Financial Institutions	$ 391
Investor−owned utilities marketers and power producers	552
Energy cooperatives and municipalities	282
Other	58
Total	$ 1,283

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, 2011, 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 2— 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, 2011, PECO had no net credit exposure to 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 2—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 cash collateral from suppliers under its natural gas supply and asset management agreements; however, the natural gas asset managers have provided $14 million in parental guarantees related to these agreements. As of December 31, 2011, PECO had credit exposure of $11 million under its natural gas supply and asset management agreements with investment grade suppliers.

Collateral and Contingent−Related Features (Exelon, Generation, ComEd, and PECO)

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the sale and purchase of electric capacity, energy, fuels and emissions allowances. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. 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. Generation also enters into commodity transactions on NYMEX and ICE. The NYMEX and ICE clearing houses act as the counterparty to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margining requirements.

Generation's interest rate swap contains provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity.

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 NYMEX and ICE that are fully collateralized) was $1,014 million and $742 million as of December 31, 2011 and 2010, respectively. As of December 31, 2011 and 2010, Generation had the contractual right of offset of $928 million and $717 million, respectively, related to derivative instruments that are assets with the same counterparty under master netting agreements, resulting in a net liability position of $86 million and $25 million, respectively. If Generation had been downgraded to the investment grade rating of BBB− and Baa3, or lost its investment grade credit rating, it would have had additional collateral obligations of approximately $307 million or $1,612 million, respectively, as of December 31, 2011 and approximately $57 million or $944 million, respectively, as of December 31, 2010 related to its financial instruments, including derivatives, non−derivatives, normal purchase normal and sales contracts and applicable payables and receivables, net of the contractual right of offset under master netting agreements and the application of collateral. See Note 18—Commitments and Contingencies for information regarding the letters of credit supporting the cash collateral.

Generation entered into SFCs with certain utilities, including PECO, 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, 2011, ComEd held both cash and letters of credit for the purpose of collateral from suppliers in association with energy procurement contracts. These amounts were not material. Beginning in June 2010, under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, beginning in December 2010, 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, 2011, 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 2—Regulatory Matters 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, 2011, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of December 31, 2011, PECO could have been required to post approximately $54 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.

Exelon's interest rate swaps contain provisions that, in the event of a merger, require that Exelon's debt maintain an investment grade credit rating from Moody's or S&P. If Exelon's debt were to fall below investment grade, 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, 2011, Exelon's interest rate swap was in an asset position, with a fair value of $15 million.

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

Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon and Generation)

As of December 31, 2011 and 2010, $2 million and $1 million, respectively, of cash collateral received was not offset against net derivative positions, because it was not associated with energy−related derivatives.

10. Debt and Credit Agreements (Exelon, Generation, ComEd and PECO)

Short−Term Borrowings

Exelon and ComEd 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.

Exelon, Generation, ComEd and PECO had the following amounts of commercial paper borrowings at December 31, 2011 and 2010:

Commercial Paper Issuer	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,	
	2011 (a)	2010 (a)	2011	2010	2011	2010
Exelon Corporate	$ 500	$ 957	$ 161	$ —	0.42%	—
Generation	5,600	4,834	—	—	0.48%	—
ComEd	1,000	1,000	—	—	0.71%	0.74%
PECO	600	574	—	—	—	—
Total	$ 7,700	$ 7,365	$ 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 commercial paper outstanding does not reduce available capacity under a Registrant's credit agreement, a Registrant does not issue commercial paper in an aggregate amount exceeding the available capacity under its credit agreement.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2011, the Registrants had the following aggregate bank commitments, credit facility borrowings and available capacity under the credit agreements:

Borrower	Aggregate Bank Commitment (a)	Facility Draws	Outstanding Letters of Credit	Available Capacity at December 31, 2011: Actual	Available Capacity at December 31, 2011: To Support Additional Commercial Paper	Average Interest Rate on Facility Borrowings for the year ended December 31, 2011
Exelon Corporate	$ 500	$ —	$ 7	$ 493	$ 332	n.a.
Generation	5,600	—	876	4,724	4,724	n.a.
ComEd	1,000	—	1	999	999	n.a.
PECO	600	—	1	599	599	n.a.
Total	$ 7,700	$ —	$ 885	$6,815	$ 6,654	

(a) Excludes additional credit facility agreements for Generation, ComEd and PECO with aggregate commitments of $50 million, $34 million and $34 million, respectively, arranged with minority and community banks located primarily within ComEd's and PECO's service territories. These facilities expire on October 19, 2012 and are solely for issuing letters of credit. As of December 31, 2011, letters of credit issued under these agreements totaled $25 million, $21 million and $20 million for Generation, ComEd and PECO, respectively.
n.a. Not applicable.

The following tables present the short−term borrowings activity for Exelon, Generation, ComEd and PECO during 2011, 2010 and 2009:

Exelon

	2011	2010	2009
Average borrowings	$ 218	$ 125	$ 132
Maximum borrowings outstanding	600	346	523
Average interest rates, computed on a daily basis	0.50%	0.72%	0.73%
Average interest rates, at December 31	0.44%	n.a.	0.69%

Generation

	2011	2010	2009
Average borrowings	$ 51	$ —	$ —
Maximum borrowings outstanding	304	—	—
Average interest rates, computed on a daily basis	0.48%	n.a.	n.a.
Average interest rates, at December 31	n.a.	n.a.	n.a.

ComEd

	2011	2010	2009
Average borrowings	$ 36	$ 125	$ 82
Maximum borrowings outstanding	407	346	265
Average interest rates, computed on a daily basis	0.71%	0.72%	0.79%
Average interest rates, at December 31	n.a.	n.a.	0.69%

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

PECO

	2011	2010	2009
Average borrowings	$—	$—	$ 11
Maximum borrowings outstanding	—	—	290
Average interest rates, computed on a daily basis	n.a.	n.a.	0.67%
Average interest rates, computed at December 31	n.a.	n.a.	n.a.

n.a. Not applicable.

Credit Agreements

On March 23, 2011, Exelon Corporate, Generation and PECO replaced their unsecured revolving credit facilities with new facilities with aggregate bank commitments of $500 million, $5.3 billion and $600 million, respectively. Under these facilities, Exelon, Generation and PECO may issue letters of credit in the aggregate amount of up to $200 million, $3.5 billion and $300 million, respectively. The credit facilities expire on March 23, 2016, unless extended in accordance with the terms of the agreements. Each credit facility permits the applicable borrower to request two one−year extensions. Each credit facility also allows Exelon, Generation and PECO to request increases in the aggregate commitments up to an additional $250 million, in the case of each of Exelon and PECO, and up to an additional $1 billion in the case of Generation. Any such extensions or increases are subject to the approval of the lenders party to the credit facilities in their sole discretion. Exelon Corporate, Generation and PECO incurred $3 million, $37 million and $4 million, respectively, in costs related to the replacement of their credit facilities. These costs included upfront and arranger fees, as well as other costs such as external legal fees and filing costs. These costs will be amortized to interest expense over the terms of the credit facilities.

As of December 31, 2011, ComEd had access to an unsecured revolving credit facility with aggregate bank commitments of $1 billion that expires on March 25, 2013, unless extended in accordance with its terms. Under this facility, ComEd may issue letters of credit in the aggregate amount of up to $1 billion. ComEd may request two additional one−year extensions. In addition, ComEd may request increases in the aggregate bank commitments under its credit facility up to an additional $500 million. Any such extensions or increases are subject to the approval of the lenders party to the credit facility in their sole discretion. ComEd expects to refinance their unsecured revolving credit facility in the first half of 2012.

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.

Borrowings under each credit agreement bear interest at a rate selected by the borrower based upon either the prime rate or at a fixed rate for a specified period based upon a LIBOR−based rate. The Exelon, Generation and PECO agreements provide for adders of up to 85 basis points for prime−based borrowings and up to 185 basis points for the LIBOR−based borrowings based upon the credit rating of the borrower. At December 31, 2011, Exelon, Generation and PECO adders were 30, 30 and 10 basis points, respectively, for prime based borrowings and 130, 130 and 110 basis points, respectively, for LIBOR−based borrowings. The ComEd agreement provides adders of up to 137.5 basis points for prime−based borrowings and up to 237.5 basis points for LIBOR−based borrowings to be added, based upon ComEd's credit rating. At December 31, 2011, ComEd's adder was 87.5 basis points for prime based borrowings and 187.5 basis points for LIBOR−based borrowings.

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

Additionally, on November 4, 2010, Generation entered into a bilateral credit facility, which provides for an aggregate commitment of up to $500 million. The effectiveness and full availability of the credit facility were subject to various conditions. On February 22, 2011, Generation satisfied all conditions to the effectiveness and availability of credit under the credit facility for loans and letters of credit in the aggregate maximum amount of $300 million, which is the limit currently authorized by the board of directors of Exelon for this credit facility. Availability under the bilateral credit facility extends through December 2015 for $150 million of the $300 million commitment and March 2016 for the remaining $150 million. The bilateral credit facility will be used by Generation primarily to meet requirements for letters of credit, but also permits cash borrowings at a rate of LIBOR or a base rate, plus an adder of 200 basis points. No cash borrowings are anticipated under the credit facility. In addition, Generation will pay a facility fee, payable on the first day of each calendar quarter at a rate per annum equal to a specified facility fee rate on the total amount of the credit facility regardless of usage.

Each credit agreement 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, 2011:

	Exelon	Generation	ComEd	PECO
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1

At December 31, 2011 the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO
Interest coverage ratio	15.60	27.98	6.39	8.21

Accounts Receivable Agreement

PECO is party to an agreement with a financial institution under which it transferred an undivided interest, adjusted daily, in its customer accounts receivable designated under the agreement in exchange for proceeds of $225 million, which is classified as a short−term note payable on Exelon's and PECO's Consolidated Balance Sheets. As of December 31, 2011 and 2010, the financial institution's undivided interest in Exelon's and PECO's customer accounts receivable was equivalent to $329 million and $346 million, respectively, which is calculated under the terms of the agreement. 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 September 2, 2011, PECO extended this agreement, which now terminates on August 31, 2012. As of December 31, 2011, 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.

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

Long−Term Debt

The following tables present the outstanding long−term debt at Exelon, Generation, ComEd and PECO as of December 31, 2011 and 2010:

Exelon

	Rates	Maturity Date	December 31, 2011	December 31, 2010
Long−term debt (a) (b):				
First Mortgage Bonds				
Fixed rates	1.65% — 7.65%	2012−2038	$ 7,522	$ 6,917
Floating rates	0.24% — 0.27%	2017−2021	—	191
Senior unsecured notes (c)	4.90% — 6.25%	2014−2041	4,902	4,902
Notes payable and other	6.95% — 7.83%	2012−2020	174	176
Pollution control notes:				
Fixed rates	5.00%	2042	46	46
Sinking fund debentures	4.75%	2011	—	2
Total long−term debt			12,644	12,234
Unamortized debt discount and premium, net			(32)	(34)
Unamortized settled fair value hedge, net			—	(1)
Fair value hedge carrying value adjustment, net			15	14
Long−term debt due within one year			(828)	(599)
Long−term debt			$ 11,799	$ 11,614
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
Total long−term debt to financing trusts			$ 390	$ 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 $34 million and $36 million at December 31, 2011 and 2010, respectively. Lease payments of $3 million, $3 million, $3 million, $3 million, $4 million and $18 million will be made in 2012, 2013, 2014, 2015, 2016 and thereafter, respectively.
(d) Amounts owed to these financing trusts are recorded as debt to financing trusts within Exelon’s Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

	Rates	Maturity Date	December 31, 2011	December 31, 2010
Long−term debt				
Senior unsecured notes	5.20% — 6.25%	2014−2041	$ 3,602	$ 3,602
Pollution control notes:				
Fixed rates	5.00%	2042	46	46
Notes payable and other (a)	7.83%	2012−2020	34	36
Total long−term debt			3,682	3,684
Unamortized debt discount and premium, net			(5)	(5)
Long−term debt due within one year			(3)	(3)
Long−term debt			$ 3,674	$ 3,676

(a) Includes Generation's capital lease obligations of $34 million and $36 million at December 31, 2011 and 2010, respectively. Generation will make lease payments of $3 million, $3 million, $3 million, $3 million, $4 million and $18 million in 2012, 2013, 2014, 2015, 2016 and thereafter, respectively.

ComEd

	Rates	Maturity Date	December 31, 2011	December 31, 2010
Long−term debt (a) (b):				
First Mortgage Bonds				
Fixed rates	1.65% — 7.65%	2012−2038	$ 5,547	$ 4,692
Floating rates	0.24% — 0.27%	2017−2021	—	191
Notes payable	6.95%	2018	140	140
Sinking fund debentures	4.75%	2011	—	2
Total long−term debt			5,687	5,025
Unamortized debt discount and premium, net			(22)	(24)
Long−term debt due within one year			(450)	(347)
Long−term debt			$ 5,215	$ 4,654
Long−term debt to financing trust (c)				
Subordinated debentures to ComEd Financing III	6.35%	2033	$ 206	$ 206

(a) Substantially all of ComEd's assets other than expressly excepted property are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the ComEd mortgage indenture securing pollution control bonds and notes.
(c) Amount owed to this financing trust is recorded as debt to financing trust within ComEd's Consolidated Balance Sheets.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

PECO

	Rates	Maturity Date	December 31, 2011	2010
Long−term debt [(a) (b)]:				
First Mortgage Bonds				
Fixed rates	4.00% — 5.95%	2012−2037	$ 1,975	$ 2,225
Total long−term debt			1,975	2,225
Unamortized debt discount and premium, net			(3)	(3)
Long−term debt due within one year			(375)	(250)
Long−term debt			$ 1,597	$ 1,972
Long−term debt to financing trusts [(c)]				
Subordinated debentures to PECO Trust III	7.38%	2028	$ 81	$ 81
Subordinated debentures to PECO Trust IV	5.75%	2033	103	103
Long−term debt to financing trusts			$ 184	$ 184

(a) Substantially all of PECO's assets are subject to the lien of its mortgage indenture.
(b) Includes First Mortgage Bonds issued under the PECO mortgage indenture securing pollution control bonds and notes.
(c) Amount owed to this financing trust is recorded as debt to financing trust within PECO's Consolidated Balance Sheets.

Long−term debt maturities at Exelon, Generation, ComEd and PECO in the periods 2012 through 2016 and thereafter are as follows:

Year	Exelon	Generation	ComEd	PECO
2012	$ 828	$ 3	$ 450	$ 375
2013	555	3	252	300
2014	1,370	503	617	250
2015	1,063	3	260	—
2016	669	4	665	—
Thereafter	8,549[(a)]	3,166	3,649[(b)]	1,234[(c)]
Total	$13,034	$ 3,682	$5,893	$2,159

(a) Includes $390 million due to ComEd and PECO financing trusts.
(b) Includes $206 million due to ComEd financing trust.
(c) Includes $184 million due to PECO financing trusts.

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. As of December 31, 2011, no draws had been made on the loan.

In addition, Generation has issued letters of credit to support its equity investment in the project. As of December 31, 2011, Generation had $690 million in letters of credit outstanding related to the project, which included approximately $635 million letters of credit issued by Generation on

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

December 21, 2011 to support its equity investment in the project prior to the initial loan advance to Antelope Valley. Due to a delay in the initial loan funding, Generation has reduced the outstanding letters of credit. As of February 8, 2012, Generation had $5 million in letters of credit outstanding related to the project. See Note 3—Merger and Acquisitions for additional information on Antelope Valley.

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. See Note 6—Derivative Financial Instruments for additional information on the interest rate swap.

11. Income Taxes (Exelon, Generation, ComEd and PECO)

Income tax expense (benefit) from continuing operations is comprised of the following components:

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Included in operations:				
Federal				
Current	$ 1	$ 431	$ (329)	$ (71)
Deferred	1,200	435	544	223
Investment tax credit amortization	(12)	(7)	(3)	(2)
State				
Current	(3)	74	(123)	(37)
Deferred	271	123	161	33
Total	$1,457	$ 1,056	$ 250	$ 146

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Included in operations:				
Federal				
Current	$ 506	$ 372	$ (203)	$ 464
Deferred	972	635	496	(276)
Investment tax credit amortization	(12)	(7)	(3)	(2)
State				
Current	171	65	(22)	87
Deferred	21	113	89	(121)
Total	$1,658	$ 1,178	$ 357	$ 152

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Included in operations:				
Federal				
Current	$ 803	$ 631	$ (39)	$ 329
Deferred	775	648	228	(143)
Investment tax credit amortization	(12)	(7)	(3)	(2)
State				
Current	154	131	4	26
Deferred	(8)	30	39	(64)
Total	$1,712	$ 1,433	$ 229	$ 146

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

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, 2011	Exelon	Generation	ComEd	PECO
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:				
State income taxes, net of Federal income tax benefit	4.4	4.5	3.6	(0.5)
Qualified nuclear decommissioning trust fund income	0.5	0.7	—	—
Domestic production activities deduction	(0.3)	(0.4)	—	—
Tax exempt income	(0.2)	(0.2)	—	—
Health care reform legislation	(0.2)	—	(1.0)	—
Amortization of investment tax credit	(0.3)	(0.3)	(0.4)	(0.3)
Production tax credits	(0.9)	(1.2)	—	—
Plant basis differences	(1.0)	—	(0.3)	(6.9)
Other	(0.1)	(0.7)	0.6	—
Effective income tax rate	36.9%	37.4%	37.5%	27.3%

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:				
State income taxes, net of Federal income tax benefit	3.0	3.7	6.3	(4.7)
Qualified nuclear decommissioning trust fund income	1.7	2.3	—	—
Domestic production activities deduction	(1.2)	(1.5)	—	—
Tax exempt income	(0.1)	(0.2)	—	—
Health care reform legislation	1.4	0.7	1.4	1.6
Amortization of investment tax credit	(0.3)	(0.2)	(0.4)	(0.4)
Plant basis differences	—	—	(0.1)	0.2
Uncertain tax position remeasurement	—	(2.0)	9.0	—
Other	(0.2)	(0.4)	0.2	0.2
Effective income tax rate	39.3%	37.4%	51.4%	31.9%

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:				
State income taxes, net of Federal income tax benefit	2.1	3.0	4.7	(5.0)
Qualified nuclear decommissioning trust fund losses	3.1	3.8	—	—
Domestic production activities deduction	(0.9)	(1.1)	—	—
Tax exempt income	(0.1)	(0.2)	—	—
Nontaxable postretirement benefits	(0.2)	(0.2)	(0.5)	(0.3)
Amortization of investment tax credit	(0.2)	(0.1)	(0.5)	(0.4)
Plant basis differences	—	—	(0.3)	(0.1)
Other	(0.1)	0.1	(0.4)	0.1
Effective income tax rate	38.7%	40.3%	38.0%	29.3%

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The tax effects of temporary differences, which give rise to significant portions of the deferred tax assets (liabilities), as of December 31, 2011 and 2010 are presented below:

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Plant basis differences	$(7,803)	$ (2,670)	$(3,264)	$(2,238)
Unrealized gains on derivative financial instruments	(468)	(737)	(4)	—
Deferred pension and post−retirement obligation	665	(520)	(623)	(31)
Nuclear decommissioning activities	(452)	(452)	—	—
Deferred debt refinancing costs	(37)	—	(31)	(6)
Other, net	41	338	16	135
Deferred income tax liabilities (net)	$(8,054)	$ (4,041)	$(3,906)	$(2,140)
Unamortized investment tax credits	(200)	(169)	(26)	(5)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(8,254)	$ (4,210)	$(3,932)	$(2,145)

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Plant basis differences	$(5,931)	$ (1,961)	$(2,552)	$(1,811)
Unrealized gains on derivative financial instruments	(523)	(908)	(4)	(1)
Deferred pension and post−retirement obligation	485	(550)	(635)	(37)
Nuclear decommissioning activities	(444)	(444)	—	—
Deferred debt refinancing costs	(46)	—	(38)	(7)
Goodwill	4	(1)	—	—
Other, net	(39)	295	65	81
Deferred income tax liabilities (net)	$(6,494)	$ (3,569)	$(3,164)	$(1,775)
Unamortized investment tax credits	(212)	(176)	(29)	(7)
Total deferred income tax liabilities (net) and unamortized investment tax credits	$(6,706)	$ (3,745)	$(3,193)	$(1,782)

The following table provides the Registrants' carryforwards and any corresponding valuation allowances as of December 31, 2011. Generation and ComEd do not have any carryforwards as of December 31, 2011.

As of December 31, 2011	Exelon	PECO
State net operating loss carryforward	$ 679[(a)]	$ 164
Deferred taxes	31	11
Valuation allowance	10	—

(a) Exelon's state net operating loss carryforwards will expire beginning in 2019.

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

Tabular reconciliation of unrecognized tax benefits

The following table provides a reconciliation of the Registrants' unrecognized tax benefits as of December 31, 2011, 2010 and 2009:

	Exelon	Generation	ComEd	PECO
Unrecognized tax benefits at January 1, 2011	$ 787	$ 664	$ 72	$ 44
Increases based on tax positions related to 2011	5	1	—	4
Change to positions that only affect timing	21	24	(2)	—
Decreases based on tax positions prior to 2011	(3)	(3)	—	—
Decreases from expiration of statute of limitations	(3)	(3)	—	—
Unrecognized tax benefits at December 31, 2011	$ 807	$ 683	$ 70	$ 48

	Exelon	Generation	ComEd	PECO
Unrecognized tax benefits at January 1, 2010	$1,498	$ 633	$ 471	$ 372
Increases based on tax positions related to 2010	1	—	—	—
Decreases based on tax positions related to 2010	(2)	(2)	—	—
Change to positions that only affect timing	(262)	55	(3)	(328)
Increases based on tax positions prior to 2010	8	8	—	—
Decreases based on tax positions prior to 2010	(3)	(3)	—	—
Decreases related to settlements with taxing authorities	(452)	(26)	(396)	—
Decrease from expiration of statute of limitations	(1)	(1)	—	—
Unrecognized tax benefits at December 31, 2010	$ 787	$ 664	$ 72	$ 44

	Exelon	Generation	ComEd	PECO
Unrecognized tax benefits at January 1, 2009	$1,495	$ 468	$ 635	$ 365
Decreases based on tax positions related to 2009	(2)	(2)	—	—
Change to positions that only affect timing	19	172	(154)	7
Increases based on tax positions prior to 2009	4	3	—	—
Decreases related to settlements with taxing authorities	(18)	(8)	(10)	—
Unrecognized tax benefits at December 31, 2009	$1,498	$ 633	$ 471	$ 372

Included in Exelon's unrecognized tax benefits balance at December 31, 2011 and 2010 are approximately $804 million and $783 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 $3 million and $3 million, respectively, of unrecognized tax benefits at December 31, 2011 that, if recognized, would decrease the effective tax rate. Exelon and Generation had $4 million and $4 million, respectively, of unrecognized tax benefits at December 31, 2010 that, if recognized, would decrease the effective tax rate.

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

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 the Registrants' Consolidated Balance Sheets.

Net interest receivable (payable) as of	Exelon	Generation	ComEd	PECO
December 31, 2011	$ 74	$ 33	$ 23	$ 28
December 31, 2010	21	(22)	14	22

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 the Registrants' Consolidated Statements of Operations. The Registrants have not accrued any penalties with respect to uncertain tax positions.

Net interest expense (income) for the years ended	Exelon	Generation	ComEd	PECO
December 31, 2011	$ (56)	$ (40)	$ (14)	$ (1)
December 31, 2010	110	6	57	35
December 31, 2009	(42)	9	(62)	(5)

Reasonably possible that total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date

Nuclear Decommissioning Liabilities (Exelon and Generation)

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 United States Department of Justice (DOJ) filed its answer denying the allegations made by Generation in its complaint. No trial date has yet been assigned, but trial could occur sometime in 2012.

The trial judge assigned to the case has noted the availability of the court's Alternative Dispute Resolution (ADR) program as an alternative to a trial, but the parties have not yet met with the ADR judge. The ADR program is a non−binding process that utilizes a variety of techniques such as mediation, neutral evaluation, and non−binding arbitration that allow the parties to understand better their differences and their prospects for settlement. The DOJ presently refuses to commit to participate in ADR. As a result, it is unclear whether ADR will occur and if so, when.

In addition, in the second quarter of 2010, Entergy Corporation concluded its trial in the United States Tax Court of a similar dispute involving the assumption of decommissioning liabilities in connection with the purchase of a nuclear power plant. It is possible that a decision will be reached in that case in the next twelve months. While the decision in that case would not serve as binding precedent for AmerGen's litigation in the United States Court of Federal Claims, the reasoning of the decision may cause Generation to reevaluate the total amount of unrecognized tax benefits. Due to the possibility of quicker resolution through the ADR program and the possibility of a decision being entered in the Entergy trial, Generation believes that it is reasonably possible that the total amount of unrecognized tax benefits may significantly decrease in the next twelve months.

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

Tax Method of Accounting for Repairs

In 2009, Exelon received approval from the IRS to change its method of accounting for repair costs associated with Generation's power plants. The new tax method of accounting resulted in net positive cash flow for of approximately $210 million and approximately $160 million for 2011 and 2010, respectively. Although the IRS granted Exelon approval to change its method of accounting, the approval did not affirm the methodology used to calculate the deduction. Exelon had requested and received approval from the IRS to review its methodology through its Pre−Filing Agreement program. However, in the second quarter of 2010, Exelon was informed that the IRS suspended the Pre−Filing agreement process and instead intends to issue broad industry guidance with respect to electric generation power plants. If that broader guidance is issued, it is reasonably possible that the total amount of unrecognized tax benefits could increase or decrease within the next 12 months.

See 1999 Sale of Fossil Generating Assets in Other Tax Matters – IRS Appeals 1999−2001 section below for information regarding the amount of unrecognized tax benefits associated with this matter that could change significantly within the next 12 months.

See Competitive Transition Charges in Other Tax Matters – IRS Appeals 1999−2001 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 − 2010
Exelon and subsidiaries Illinois unitary income tax returns	2007 − 2010
Exelon Pennsylvania corporate net income tax returns	2006 − 2010
PECO Pennsylvania corporate net income tax returns	2008 − 2010

Other Tax Matters

IRS Appeals 1999−2001 (Exelon, ComEd and PECO)

1999 Sale of Fossil Generating Assets (Exelon and ComEd). 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 1999 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 believes 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.

Exelon received the IRS audit report for 1999 through 2001, which reflected the full disallowance of the deferral of gain associated with both the involuntary conversion position and the like−kind exchange transaction. Specifically, the IRS asserted that ComEd was not forced to sell the fossil generating plants and the sales proceeds were therefore not received in connection with an involuntary conversion of certain ComEd property rights. Accordingly, the IRS asserted that the gain on the sale of the assets was fully subject to tax. The IRS also 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.

Competitive Transition Charges (Exelon, ComEd, and PECO). 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 has 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, are 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.

Under the Illinois Act, ComEd was required to allow competitors the use of its distribution system resulting in the taking of ComEd's assets and lost asset value (stranded costs). As compensation for the taking, ComEd was permitted to collect a portion of the stranded costs through the collection of CTCs from those customers electing to purchase electricity from providers other than ComEd. ComEd collected approximately $1.2 billion in CTCs for the years 1999−2006.

Similarly, under the Competition Act, PECO was required to allow others the use of its distribution system resulting in the taking of PECO's assets and the stranded costs. Pennsylvania permitted PECO to collect CTCs as compensation for its stranded costs. The PAPUC determined the total amount of stranded costs that PECO was permitted to collect through the CTCs to be $5.3 billion.

2009 Status of Tax Positions. During 2009, Exelon held discussions with IRS Appeals in an attempt to reach a settlement on both the involuntary conversion and like−kind exchange positions, in a manner commensurate with Exelon's and the IRS' respective hazards of litigation with respect to each issue. During the second quarter of 2009, Exelon determined that a settlement with IRS Appeals was unlikely and that Exelon would be required to initiate litigation in order to resolve the issues. Accordingly, Exelon concluded that it had sufficient new information that a remeasurement of these two positions was required in accordance with applicable accounting standards. As a result, Exelon recorded a $31 million (after−tax) interest benefit of which $40 million (after−tax) was recorded at ComEd. The difference in amounts recorded at Exelon and ComEd is due to the method of allocating interest to the Registrants.

Due to the fact that tax litigation often results in a negotiated settlement, as of December 31, 2009, Exelon believed that an eventual settlement on the involuntary conversion position remained a likely outcome. Therefore, Exelon and ComEd established a liability for an unrecognized tax benefit consistent with their view as to a likely settlement.

With regard to the like−kind exchange transaction, as of December 31, 2009, Exelon believed it was likely that the issue would be fully litigated. Exelon assessed in accordance with accounting standards whether it would prevail in litigation. While Exelon recognized the complexity and hazards of this litigation, it believed that it was more likely than not that it would prevail in such litigation and therefore eliminated any liability for unrecognized tax benefits.

In addition to attempting to impose tax on the transactions, the IRS had asserted penalties of approximately $196 million for a substantial understatement of tax. Because Exelon believed it was unlikely that the penalty assertion would ultimately be sustained, Exelon and ComEd had not recorded a liability for penalties as of December 31, 2009.

2010 Status of Tax Positions. In connection with Exelon's discussions with IRS Appeals during the second quarter of 2010, IRS Appeals proposed a settlement offer for the like−kind exchange transaction and involuntary conversion and CTC positions.

Based on the status of these settlement discussions, Exelon concluded 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 re−measurement in the second quarter of 2010, 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 IRS Appeals reached a nonbinding, preliminary agreement to settle Exelon's involuntary conversion and CTC positions. The agreement is consistent with IRS Appeals' second quarter 2010 offer to settle the involuntary conversion and CTC positions and also includes IRS Appeals' agreement to withdraw its assertion of the $110 million substantial understatement penalty with respect to Exelon's involuntary conversion position. Final resolution of the involuntary conversion and CTC disputes remains subject to finalizing terms and calculations and executing definitive agreements satisfactory to both parties. 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.

2011 Status of Tax Positions. Under the terms of the preliminary agreement, Exelon estimates that the IRS will assess tax and interest of approximately $300 million in 2012 for the years for which there is a resulting tax deficiency, of which $405 million would be paid by ComEd, $135 million would be received by PECO, $10 million would be paid by Generation and the remainder received by Exelon. These amounts are net of approximately $300 million of refunds due from the settlement of the 2001 tax method of accounting change for certain overhead costs under the SSCM as well as other agreed upon audit adjustments. In order to stop additional interest from accruing on the expected assessment, Exelon made a payment in December 2010 to the IRS of $302 million. During 2011, ComEd reimbursed Exelon for this amount. Further, Exelon expects to receive additional tax refunds of approximately $365 million between 2012 and 2014, of which $55 million and $335 million would be received by Generation and ComEd, respectively, and the remainder paid by Exelon.

Exelon and IRS Appeals to date have failed to reach a settlement with respect to the like−kind exchange position. Exelon continues to believe that its like−kind exchange transaction is not the same as or substantially similar to a SILO and does not believe that the concession demanded by the IRS in its settlement offer reflects the strength of Exelon's position. IRS Appeals also continues to assert an $86 million penalty for a substantial understatement of tax with respect to the like−kind exchange position.

While Exelon has been and remains willing to settle the issue in a manner generally commensurate with its hazards of litigation, the IRS has thus far been unwilling to settle the issue without requiring a nearly complete concession of the issue by Exelon. Accordingly, to continue to contest the IRS's disallowance of the like−kind exchange position and its assertion of the $86 million substantial understatement penalty, Exelon expects to initiate litigation in 2012 after the final resolution of the involuntary conversion and CTC settlement. Given that Exelon has determined settlement is not a realistic outcome, it has assessed in accordance with applicable accounting standards whether it will prevail in litigation. While Exelon recognizes the complexity and hazards of this litigation, it believes that it is more likely than not that it will prevail in such litigation and therefore eliminated any liability for unrecognized tax benefits. Further, Exelon believes it is unlikely that the penalty assertion will ultimately be sustained, Exelon and ComEd have not recorded a liability for penalties. However, should the IRS prevail in asserting the penalty it would result in an after−tax charge of $86 million to Exelon's and ComEd's results of operations.

As of December 31, 2011, assuming Exelon's preliminary settlement of the involuntary conversion position is finalized, the potential tax and interest, exclusive of penalties, that could become currently payable in the event of a fully successful IRS challenge to Exelon's like−kind exchange position could be as much as $860 million, of which $550 million would be paid by ComEd and the remainder by Exelon. If the IRS were to prevail in litigation on the like−kind exchange position, Exelon's results of operations could be negatively affected due to increased interest expense, as of December 31, 2011, by as much as $260 million (after−tax), of which $200 million would be recorded at ComEd and the remainder by Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

Based on Exelon management's expectations as to the potential of a settlement and litigation outcome, it is reasonably possible that the unrecognized tax benefits related to these issues may significantly change within the next 12 months. It is not possible at this time to predict the amount, if any, of such a change.

Nuclear Decommissioning Trust Fund Special Transfer Tax Deduction (Exelon and Generation)

During 2008, Generation benefited from a provision in the Energy Policy Act of 2005 which allowed companies an income tax deduction for a "special transfer" of funds from a non−tax qualified NDT fund to a qualified NDT fund. As a result of temporary guidance published by the U.S. Department of Treasury, Generation completed a special transfer in the first quarter of 2008 for tax year 2008. In December 2010, the U.S. Department of Treasury issued final regulations under IRC Section 468A. The final regulations included a transitional relief provision that allowed taxpayers to request permission from the IRS to designate a taxable year, as far back as 2006, during which the special transfer will be deemed to have occurred. Exelon determined, and confirmed with the IRS through the ruling process, that this provision allows a majority of Generation's 2008 special transfer deduction to be claimed in the 2006 tax year and the remaining portions claimed ratably in taxable years 2007 and 2008. On February 18, 2011, in order to preserve both the ability to designate the special transfer from 2008 to an earlier taxable year and the ability to complete future additional special transfers, Exelon filed ruling requests with the IRS. During 2011, Exelon received favorable rulings from the IRS on all of its ruling requests. As a result, Exelon recorded an interest and tax benefit of $46 million, net of tax including the impact on the manufacturer's deduction, in 2011 related to the special transfers completed in 2008 and 2011.

2011 Illinois State Tax Rate Legislation (Exelon, Generation and ComEd)

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)

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. On April 16, 2009, the PAPUC approved PECO's electricity procurement proposal that has an impact on Exelon's and Generation's apportionment of income among the states. Accordingly, Exelon and Generation re−evaluated the impacts to deferred state taxes in the second quarter of 2009. The effect of such evaluations resulted in the recording of a non−cash deferred state tax benefit in the amount of $35 million, net of 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.

Illinois Replacement Investment Tax Credits (Exelon, Generation and ComEd)

On February 20, 2009, the Illinois Supreme Court ruled in Exelon's favor in a case involving refund claims for Illinois investment tax credits. Responding to the Illinois Attorney General's petition for rehearing, on July 15, 2009, the Illinois Supreme Court modified its opinion to indicate that it was to be applied only prospectively, beginning in 2009. In the third quarter of 2009, Exelon, Generation and ComEd decreased their unrecognized tax benefits related to this position. On December 22, 2009, Exelon filed a Petition of Writ for Certiorari with the United States Supreme Court appealing the Illinois Supreme Court's July 15, 2009 modified opinion. On March 1, 2010, the United States Supreme Court announced that it would not review the Illinois Supreme Court's decision. As a result of the United States Supreme Court decision, Exelon, Generation and ComEd ceased reporting their unrecognized tax benefits as of March 31, 2010.

Pennsylvania Bonus Depreciation (Exelon, Generation and PECO)

Pursuant to authoritative guidance issued by the Pennsylvania Department of Revenue on February 24, 2011, Exelon is permitted to deduct 100% bonus depreciation in Pennsylvania in the year that such depreciation is claimed and allowable for Federal purposes. For Federal purposes, qualifying property placed into service after September 8, 2010, and before January 1, 2012, is eligible for 100% bonus depreciation. During 2011, the bonus depreciation deduction resulted in a benefit of approximately $7 million, $1 million and $6 million associated with property placed in service in 2010 at Exelon, Generation and PECO, respectively.

Accounting for Electric Transmission and Distribution Property Repairs (Exelon, Generation, ComEd and PECO)

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 intends to adopt the safe harbor in the Revenue Procedure for the 2011 tax year. PECO adopted the safe harbor for the 2010 tax year. 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 will result in a cash tax benefit at Exelon, ComEd and PECO in the amount of approximately $300 million, $250 million and $95 million, respectively, partially offset by a cash tax detriment at Generation in the amount of $28 million.

See Note 2 – 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.

Allocation of Tax Benefits (Exelon, Generation, ComEd and PECO)

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 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. During 2009, Generation, ComEd and PECO recorded an allocation of Federal tax benefits from Exelon under the Tax Sharing Agreement of $57 million, $8 million and $27 million, respectively.

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

In addition, ComEd received a non−cash contribution to equity from Exelon of $11 million related to tax benefits associated with capital projects constructed by ComEd on behalf of Exelon and Generation.

12. Asset Retirement Obligations (Exelon, Generation, ComEd and PECO)

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. The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets, from January 1, 2010 to December 31, 2011:

	Exelon and Generation
Nuclear decommissioning ARO at January 1, 2010	$ 3,260
Accretion expense	191
Net increase due to changes in estimated future cash flows	624
Extinguishment of Zion Station ARO	(768)
Costs incurred to decommission retired plants	(31)
Nuclear decommissioning ARO at December 31, 2010 [(a)]	3,276
Accretion expense	209
Net increase due to changes in estimated future cash flows	198
Costs incurred to decommission retired plants	(3)
Nuclear decommissioning ARO at December 31, 2011 [(a)]	$ 3,680

(a) Includes $5 million as the current portion of the ARO at December 31, 2011 and 2010, which is included in other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

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 and Generation'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.

During 2010, Generation recorded a net increase in the ARO of $16 million, primarily reflecting ZionSolutions' assumption of decommissioning and other liabilities for Zion Station (see discussion below); and increases for accretion and for updates to estimated future cash flows across all of Generation's units. Changes in estimated future cash flows increased the ARO by $624 million, including approximately $200 million associated with the accelerated timing of the Zion Station decommissioning. The remainder of the increase is the result of cost study estimate updates and the change in timing of general decommissioning activities at select sites in Generation's nuclear fleet, including revisions to the timing and amount of SNF disposal; partially offset by the impacts of lower escalation rates. This change in the ARO resulted in an immaterial impact to Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

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 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. ZionSolutions and Bank of New York Mellon filed a motion to dismiss the complaint on September 13, 2011.

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 Generation and 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 Generation and 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 $65 million and $34 million at December 31, 2011 and 2010, 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. As of December 31, 2011 and 2010, the carrying value of the Zion Station pledged assets was approximately $734 million and $824 million, respectively, and the payable to Zion Solutions was approximately $691 million and $786 million, respectively. The payable excludes a liability recorded within Generation'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. The current portion of the payable to ZionSolutions, included in other current liabilities within Generation's Consolidated Balance Sheets at December 31, 2011 and 2010 was $128 million and $127 million, respectively. ZionSolutions withdrew approximately $143 million and $5 million for Zion Station decommissioning costs during the years ended December 31, 2011 and 2010, respectively.

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 reflecting updated fund balances and estimated decommissioning costs. The most recent rate adjustment occurred on January 1, 2008 and the effective rates currently yield annual collections of $29 million. The next five−year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2013. 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, 2011 and 2010, Exelon and Generation had NDT fund investments totaling $6,507 million and $6,408 million, respectively.

During 2011, the NDT fixed income strategy shifted from solely core fixed income investments to a blend of Treasury Inflation Protected Securities (TIPS), investment−grade corporate credit and short−term corporate lending. There was no change in the equity investment strategy. At December 31, 2011, approximately 48% of the funds were invested in equity securities and 52% were invested in fixed income securities. At December 31, 2010, approximately 57% of the funds were invested in equity securities and 43% were invested in fixed income securities.

Securities Lending Program. Generation's NDT funds currently participate in a securities lending program with the funds' trustees. Under the program, securities loaned by the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re−pledged by the trustees unless the borrower defaults.

In the fourth quarter of 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral pools is approximately 13 months. The fair value of securities on loan was approximately $20 million and $51 million at December 31, 2011 and 2010, respectively. The fair value of cash and non−cash collateral received for these loaned securities was $19 million and $51 million at December 31, 2011 and 2010, respectively. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

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, 2011 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, 2011 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 6.1% 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 5.6% to 6.7% (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 10, 2010, Generation notified the NRC that it had provided additional decommissioning funding assurance for its Byron Unit 2 and Braidwood Units 1 and 2 NDT funds with the establishment of approximately $44 million in parent guarantees in accordance with a plan submitted by Generation to the NRC on July 29, 2009. On May 26, 2010, the NRC notified Generation that additional parent guarantees may be required to meet the future value of the underfunded position. During the third quarter of 2010, Generation established approximately $175 million in additional parent guarantees.

On March 31, 2011, Generation, in its NRC−required biennial decommissioning funding status report, notified the NRC that adequate decommissioning funding assurance existed as of December 31, 2010 for Byron Unit 2 and Braidwood Units 1 and 2, without taking credit for any additional funding assurance provided by the parent guarantees, and Generation provided notice of its intention to cancel the parent guarantees following expiration of the NRC required notice period. Accordingly, Generation cancelled these parent guarantees on August 6, 2011. Additionally, in the March 31, 2011 report, Generation 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. As Generation noted in its March 31, 2011 report, the funding mechanism used as the source of revenues for the Limerick Unit 1 NDT funds is a non−bypassable charge approved by the PAPUC authorizing PECO to continue to collect decommissioning funds from ratepayers for Generation. Generation is currently evaluating several options for addressing NRC funding assurance requirements. These options will not result in an increase to the non−bypassable charge and may include other financial guarantees, such as a parent company guarantee. Every five years, PECO files a cost adjustment with the PAPUC reflecting updated fund balances and estimated decommissioning costs. The next cost adjustment filing will be made in March 2012 and will be effective January 1, 2013.

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 and Generation'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, 2011, 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, 2011 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 and Generation'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 and Generation's Consolidated Statements of Operations and Comprehensive Income, as there are no regulatory agreements associated with these units.

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

Refer to Note 19—Supplemental Financial Information and Note 21—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 2011, 2010 and 2009:

	Exelon and Generation		
	For the Years Ended December 31,		
	2011	2010	2009
Net unrealized gains (losses) on decommissioning trust funds—Regulatory Agreement Units [(a) (b)]	$(74)	$294	$799
Net unrealized gains (losses) on decommissioning trust funds—Non−Regulatory Agreement Units [(c)]	(4)	104	227

(a) Gains related to Generation's NDT funds associated with Regulatory Agreement Units are included in regulatory liabilities on Exelon's Consolidated Balance Sheets and noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $48 million and $20 million of gains related to the Zion Station pledged assets in 2011 and 2010. Gains related to Zion Station pledged assets are included in the payable for Zion Station decommissioning on Exelon's and Generation's Consolidated Balance Sheets.
(c) Gains related to Generation's NDT funds associated with Non−Regulatory Agreement Units are included within Other, net in Exelon's and Generation'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 (Exelon, Generation, ComEd, and PECO)

Generation has AROs for plant closure costs associated with its fossil, hydroelectric and renewable generating stations, 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 and PECO have AROs primarily associated with the abatement and disposal of equipment and buildings contaminated with asbestos and PCBs. See Note 1—Significant Accounting Policies for additional information on the Registrants' accounting policy for AROs.

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

The following table provides a rollforward of the non−nuclear AROs reflected on the Registrants' Consolidated Balance Sheets from January 1, 2010 to December 31, 2011:

	Exelon	Generation	ComEd	PECO
Non−nuclear AROs at January 1, 2010	$ 191	$ 73	$ 95	$ 24
Net increase (decrease) resulting from updates to estimated future cash flows (a)	13	(3)	8	8
Accretion expense (b)	9	3	4	1
Acquisition of Exelon Wind (c)	13	13	—	—
Payments	(3)	—	(2)	(1)
Non−nuclear AROs at December 31, 2010	223	86	105	32
Net increase (decrease) resulting from updates to estimated future cash flows (a)	(19)	2	(17)	(4)
New development projects	2	2	—	—
Accretion expense (b)	8	4	3	1
Payments	(5)	(2)	(2)	(1)
Non−nuclear AROs at December 31, 2011	$ 209	$ 92	$ 89	$ 28

(a) ComEd and PECO recorded reductions in operating and maintenance expense of $10 million and $1 million, respectively, during the year ended December 31, 2010 and PECO recorded a reduction in operating and maintenance expense of $3 million during the year ended December 31, 2011 relating to updates to estimated future cash flows.
(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) Refer to Note 3—Acquisition for additional information regarding Exelon Wind.

13. Retirement Benefits (Exelon, Generation, ComEd and PECO)

As of December 31, 2011, Exelon sponsored five qualified defined benefit pension plans, two non−qualified defined benefit pension plans and three other postretirement benefit plans for essentially all Generation, ComEd, PECO and BSC employees. The table below shows the pension and postretirement benefit plans in which each operating company participated at December 31, 2011.

	Operating Company			
Name of Plan:	Generation	ComEd	PECO	BSC
Qualified Pension Plans:				
Exelon Corporation Retirement Program	X	X	X	X
Exelon Corporation Cash Balance Pension Plan	X	X	X	X
Exelon Corporation Pension Plan for Bargaining Unit Employees	X	X		X
Exelon New England Union Employees Pension Plan	X			
Exelon Employee Pension Plan for Clinton, TMI and Oyster Creek	X		X	X
Non−Qualified Pension Plans:				
Exelon Corporation Supplemental Pension Benefit Plan and 2000 Excess Benefit Plan			X	X
	X	X		
Exelon Corporation Supplemental Management Retirement Plan	X	X	X	X
Other Postretirement Benefit Plans:				
PECO Energy Company Retiree Medical Plan	X		X	X
Exelon Corporation Health Care Program	X	X		X
AmerGen Energy Company Postretirement Welfare Plan	X		X	X

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

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 impact of changes in assumptions used to measure pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants. 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	
	2011	2010	2011	2010
Change in benefit obligation:				
Net benefit obligation at beginning of year	$12,524	$11,482	$ 3,874	$ 3,658
Service cost	212	190	142	124
Interest cost	649	660	207	214
Plan participants' contributions	—	—	25	16
Actuarial loss	807	831	4	49
Special termination benefits	—	—	—	1
Gross benefits paid	(654)	(639)	(201)	(198)
Federal subsidy on benefits paid	—	—	11	10
Net benefit obligation at end of year	$13,538	$12,524	$ 4,062	$ 3,874
Change in plan assets:				
Fair value of net plan assets at beginning of year	$ 8,859	$ 7,839	$ 1,655	$ 1,476
Actual return on plan assets	1,003	893	29	158
Employer contributions	2,094	766	277	203
Plan participants' contributions	—	—	25	16
Benefits paid[(a)]	(654)	(639)	(189)	(198)
Fair value of net plan assets at end of year	$11,302	$ 8,859	$ 1,797	$ 1,655

(a) Exelon's other postretirement benefits paid for the year ended December 31, 2011 are net of $12 million 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.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Exelon presents its benefit obligations and plan assets net on its balance sheet within the following line items:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Other current liabilities	$ 42	$ 7	$ 2	$ 1
Pension obligations	2,194	3,658	—	—
Non−pension postretirement benefit obligations	—	—	2,263	2,218
Unfunded status (net benefit obligation less net plan assets)	$2,236	$3,665	$ 2,265	$ 2,219

The funded status of the pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations of the plan. The funded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following tables provide the projected benefit obligations (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for all pension plans with an ABO in excess of plan assets and a PBO in excess of plan assets.

	PBO and ABO in excess of plan assets	
	2011	2010
Projected benefit obligation	$13,538	$12,524
Accumulated benefit obligation	12,616	11,697
Fair value of net plan assets	11,302	8,859

On an ABO basis, the plans were funded at 90% at December 31, 2011 compared to 76% at December 31, 2010. On a PBO basis, the plans were funded at 83% at December 31, 2011 compared to 71% at December 31, 2010. The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

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

Table of Contents

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2011, 2010 and 2009 for all plans combined. The table reflects a reduction in 2011, 2010 and 2009 of net periodic postretirement benefit costs of approximately $28 million, $38 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		
	2011	2010	2009	2011	2010	2009
Components of net periodic benefit cost:						
Service cost	$ 212	$ 190	$ 178	$ 142	$ 124	$113
Interest cost	649	660	651	207	214	205
Expected return on assets	(939)	(799)	(778)	(111)	(109)	(94)
Amortization of:						
Transition obligation	—	—	—	9	9	9
Prior service cost (credit)	14	14	14	(38)	(56)	(56)
Actuarial loss	331	254	197	66	74	87
Curtailment/settlement charges	—	5	6	—	—	—
Special termination benefits	—	—	—	—	1	4
Net periodic benefit cost	$ 267	$ 324	$ 268	$ 275	$ 257	$268

Through Exelon’s postretirement benefit plans, the Registrants provide 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, 2011, 2010 and 2009 included in the consolidated financial statements was as follows:

	2011	2010	2009
Amortization of the actuarial experience loss	$ 3	$ 9	$ 11
Reduction in current period service cost	9	10	9
Reduction in interest cost on the APBO	16	19	18
Total effect of subsidy on net periodic postretirement benefit cost	$ 28	$ 38	$ 38

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

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, 2011, 2010 and 2009 for all plans combined.

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
Changes in plan assets and benefit obligations recognized in AOCI and regulatory assets:						
Current year actuarial (gain) loss	$ 744	$ 737	$ (94)	$ 74	$ —	$ (154)
Amortization of actuarial loss	(331)	(254)	(197)	(66)	(74)	(87)
Current year prior service cost	—	—	2	—	—	—
Amortization of prior service cost (credit)	(14)	(14)	(14)	38	56	56
Amortization of transition obligation	—	—	—	(9)	(9)	(9)
Settlements	—	(5)	(6)	—	—	—
Total recognized in AOCI and regulatory assets (a)	$ 399	$ 464	$(309)	$ 37	$ (27)	$ (194)

(a) 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. Of the $(309) related to pension benefits, $(204) million and $(105) million were recognized in AOCI and regulatory assets, respectively, during 2009. Of the $(194) million related to other postretirement benefits, $(85) million and $(109) million were recognized in AOCI and regulatory assets, respectively, during 2009.

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, 2011 and 2010, respectively, for all plans combined:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Transition obligation	$ —	$ —	$ 11	$ 20
Prior service cost (credit)	90	104	(16)	(54)
Actuarial loss	6,729	6,316	963	955
Total (a)	$6,819	$6,420	$ 958	$ 921

(a) 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. Of the $6,420 million related to pension benefits, $4,129 million and $2,291 million are included in AOCI and regulatory assets, respectively, at December 31, 2010. Of the $921 million related to other postretirement benefits, $462 million and $459 million are included in AOCI and regulatory assets, respectively, at December 31, 2010.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table provides the components of Exelon's AOCI and regulatory assets at December 31, 2011 (included in the table above) that are expected to be amortized as components of periodic benefit cost in 2012. 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, 2012 and actual claims activity as of December 31, 2011. The valuation is expected to be completed in the first quarter of 2012.

	Pension Benefits	Other Postretirement Benefits
Transition obligation	$ —	$ 10
Prior service cost (credit)	14	(12)
Actuarial loss	407	69
Total [(a)]	$ 421	$ 67

(a) Of the $421 million related to pension benefits at December 31, 2011, $252 million and $169 million are expected to be amortized from AOCI and regulatory assets in 2012, respectively. Of the $67 million related to other postretirement benefits at December 31, 2011, $32 million and $35 million are expected to be amortized from AOCI and regulatory assets in 2012, 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 of certain 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. The impact of changes in assumptions used to measure pension and other postretirement benefit obligations is generally recognized over the expected average remaining service period of the plan participants.

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.

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

The following assumptions were used to determine the benefit obligations for all of the plans at December 31, 2011, 2010 and 2009. 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		
	2011	2010	2009	2011	2010	2009
Discount rate	4.74%	5.26%	5.83%	4.80%	5.30%	5.83%
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

The following assumptions were used to determine the net periodic benefit costs for all the plans for the years ended December 31, 2011, 2010 and 2009:

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
Discount rate	5.26%	5.83%	6.09%	5.30%	5.83%	6.09%
Expected return on plan assets	8.00%(a)	8.50%(a)	8.50%(a)	7.08%(a)	7.83%(a)	8.10%(a)
Rate of compensation increase	3.75%	4.00%	4.00%	3.75%	4.00%	4.00%
Mortality table	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2009 funding valuation	IRS required mortality table for 2011 funding valuation	IRS required mortality table for 2010 funding valuation	IRS required mortality table for 2009 funding valuation
Health care cost trend on covered charges	N/A	N/A	N/A	7.00% decreasing to ultimate trend of 5.00% in 2015	7.50% decreasing to ultimate trend of 5.00% in 2015	7.50% decreasing to ultimate trend of 5.00% in 2014

(a) Not applicable to pension and other postretirement benefit plans that do not have any plan assets.

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

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 2011 total service and interest cost components	$ 75
on postretirement benefit obligation at December 31, 2011	686
Effect of a one percentage point decrease in assumed health care cost trend:	
on 2011 total service and interest cost components	(57)
on postretirement benefit obligation at December 31, 2011	(521)

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. 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. Of this total, Generation, ComEd and PECO recorded charges of $24 million, $11 million and $9 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 intends to make a change in the manner in which it receives prescription drug subsidies in 2013.

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.

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

Contributions

Exelon allocates pension and other postretirement benefit contributions to its subsidiaries in proportion to active service costs recognized and total costs recognized, respectively. The following table provides contributions made by Generation, ComEd, PECO and BSC to the pension and other postretirement benefit plans:

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	2011 (a)	2010 (a)	2009 (a)
Generation	$ 954	$356	$201	$ 121	$ 94	$ 69
ComEd	873	260	164	108	60	53
PECO	110	73	31	28	35	22
BSC	157	77	45	20	14	13
Exelon	$2,094	$766	$441	$ 277	$ 203	$ 157

(a) The Registrants present the cash contributions above net of Federal subsidy payments received on each of their respective Consolidated Statements of Cash Flows. Exelon, Generation, ComEd and PECO received Federal subsidy payments of $11 million, $5 million, $4 million and $1 million, respectively, in 2011, $10 million, $5 million, $3 million and $2 million, respectively, in 2010, and $10 million, $5 million, $3 million and $1 million, respectively, in 2009.

Exelon plans to contribute approximately $96 million to its qualified pension plans in 2012, of which Generation, ComEd and PECO will contribute $57 million, $11 million and $16 million, respectively. Exelon plans to make non−qualified pension plan benefit payments of approximately $42 million in 2012, of which Generation, ComEd and PECO will pay $3 million, $11 million and $1 million, respectively. 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).

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 $302 million to the other postretirement benefit plans in 2012, of which Generation, ComEd and PECO expect to contribute $132 million, $114 million and $34 million, respectively.

During the first quarter of 2012, Exelon will receive an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2012 and will adjust the benefit obligations as necessary.

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

Estimated Future Benefit Payments

Estimated future benefit payments to participants in all of the pension plans and postretirement benefit plans at December 31, 2011 were:

	Pension Benefits	Other Postretirement Benefits (a)
2012	$ 786	$ 186
2013	680	178
2014	692	186
2015	723	194
2016	750	204
2017 through 2021	4,335	1,206
Total estimated future benefit payments through 2021	$ 7,966	$ 2,154

(a) 2012 includes $9 million of Federal subsidy receipts provided through the Medicare Modernization Act.

Allocation to Exelon Subsidiaries

Generation, ComEd and PECO account for their participation in Exelon's pension and other postretirement benefit plans by applying multiemployer accounting. Employee−related assets and liabilities, including both pension and postretirement liabilities, were allocated by Exelon to its subsidiaries based on the number of active employees as of January 1, 2001 as part of Exelon's corporate restructuring. Exelon allocates the components of pension and other postretirement costs to the participating employers based upon several factors, including the measures of active employee participation in each participating unit. The obligation for Generation, ComEd and PECO reflects the initial allocation and the cumulative costs incurred and contributions made since January 1, 2001.

The following approximate amounts were included in capital and operating and maintenance expense for the years ended December 31, 2011, 2010 and 2009, respectively, for Generation's, ComEd's, PECO's and BSC's allocated portion of the Exelon−sponsored pension and other postretirement benefit plans:

For the Year Ended December 31,	Generation	ComEd	PECO	BSC (a)	Exelon
2011	$ 249	$ 213	$ 32	$ 48	$ 542
2010	268	215	46	52	581
2009	240	192	47	57	536

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations.

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.

In the second quarter of 2010, Exelon modified its pension investment strategy in order to reduce the volatility of its pension assets relative to its pension liabilities. As a result of this modification, Exelon decreased investments in equity securities and increased investments in fixed income securities and alternative investments in order to achieve a balanced portfolio of liability hedging and return−generating assets. 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.

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

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. Exelon used an EROA of 7.50% and 6.68% to estimate its 2012 pension and other postretirement benefit costs, respectively.

Exelon's pension and other postretirement benefit plan target asset allocations and December 31, 2011 and 2010 weighted average asset allocations were as follows:

Pension Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2011	2010
Equity securities	30 − 40%	32%	45%
Fixed income securities (a)	35 − 55%	47	41
Alternative investments	20 − 30%	21	14
Total		100%	100%

Other Postretirement Benefit Plans

Asset Category	Target Allocation	Percentage of Plan Assets at December 31, 2011	2010
Equity securities	40 − 50%	37%	54%
Fixed income securities (a)	35 − 45%	53	45
Alternative investments	10 − 20%	10	1
Total		100%	100%

(a) Alternative investments include private equity, hedge funds and real estate.

Securities Lending Programs. The majority of the benefit plans currently participate in a securities lending program with the trustees of the plans' investment trusts. Under the program, securities loaned to the trustees are required to be collateralized by cash, U.S. Government securities or irrevocable bank letters of credit. Initial collateral levels are no less than 102% and 105% of the market value of the borrowed securities for collateral denominated in U.S. and foreign currency, respectively. Subsequent collateral levels must be maintained at a level no less than 100% of the market value of borrowed securities. Cash collateral received may not be sold or re−pledged by the trustees unless the borrower defaults.

In the fourth quarter of 2008, Exelon decided to end its participation in this securities lending program and initiated a gradual withdrawal of the trusts' investments in order to minimize potential losses due to liquidity constraints in the market. Currently, the weighted average maturity of the securities within the collateral funds is approximately 7 months. The fair value of securities on loan was approximately $17 million and $46 million at December 31, 2011 and 2010, respectively. The fair value of cash and non−cash collateral received for these loaned securities was $17 million at December 31, 2011 and $47 million at December 31, 2010. A portion of the income generated through the investment of cash collateral is remitted to the borrowers, and the remainder is allocated between the trusts and the trustees in their capacity as security agents.

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

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, 2011. 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, 2011, 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, 2011 and 2010:

At December 31, 2011 (a)(b)	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	—	—	1,525	1,525
Real estate	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

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2011 (a) (b)	Level 1	Level 2	Level 3	Total
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	—	—	157	157
Real estate	4	1	7	12
Other postretirement benefit plan assets subtotal	213	1,410	165	1,788
Total pension and other postretirement benefit plan assets	$4,029	$6,366	$2,591	$12,986

At December 31, 2010 (a) (b)	Level 1	Level 2	Level 3	Total
Pension plan assets				
Cash equivalents	$ 2	$ —	$ —	$ 2
Equity securities:				
Individually held	1,528	—	—	1,528
Commingled funds	—	2,161	—	2,161
Mutual funds	—	326	—	326
Equity securities subtotal	1,528	2,487	—	4,015
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,144	20	—	1,164
Debt securities issued by states of the United States and by political subdivisions of the states	—	15	—	15
Foreign debt securities	—	73	—	73
Corporate debt securities	—	312	—	312
Federal agency mortgage−backed securities	—	226	—	226
Non−Federal agency mortgage−backed securities	—	82	—	82
Commingled funds	—	1,036	—	1,036
Mutual funds	—	666	—	666
Fixed income securities subtotal	1,144	2,430	—	3,574
Private equity	—	—	536	536
Hedge funds	—	—	329	329
Real estate	178	—	179	357
Pension plan assets subtotal	2,852	4,917	1,044	8,813

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

Table of Contents

At December 31, 2010 (a) (b)	Level 1	Level 2	Level 3	Total
Other postretirement benefit plan assets				
Cash equivalents	—	—	—	—
Equity securities:				
Individually held	225	—	—	225
Commingled funds	—	447	—	447
Mutual funds	—	218	—	218
Equity securities subtotal	225	665	—	890
Fixed income securities:				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	25	1	—	26
Debt securities issued by states of the United States and by political subdivisions of the states	—	100	—	100
Foreign debt securities	—	1	—	1
Corporate debt securities	—	13	—	13
Federal agency mortgage−backed securities	—	41	—	41
Non−Federal agency mortgage−backed securities	—	7	—	7
Commingled funds	—	225	—	225
Mutual funds	—	331	—	331
Fixed income securities subtotal	25	719	—	744
Hedge funds	—	—	5	5
Real estate	8	—	8	16
Other postretirement benefit plan assets subtotal	258	1,384	13	1,655
Total pension and other postretirement benefit plan assets	$3,110	$6,301	$1,057	$10,468

(a) See Note 8—Fair Value of Assets and Liabilities for a description of levels within the fair value hierarchy.
(b) The total fair value of pension and other postretirement benefit plan assets excludes $55 million and $21 million of interest and dividends receivable and $57 million and $25 million related to pending sales transactions at December 31, 2011 and 2010, respectively. Additionally, the table excludes collateral fund assets of $17 million and $47 million and collateral liabilities of $17 million and $47 million at December 31, 2011 and 2010, respectively, in connection with the benefit plans' participation in securities lending programs.

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value for pension and other postretirement benefit plans for the years ended December 31, 2011 and 2010:

	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:				
Relating to assets still held at the reporting date	(26)	50	46	70
Purchases, sales and settlements:				
Purchases	1,222	121	13	1,356
Sales	—	(1)	(9)	(10)
Settlements	—	(34)	—	(34)
Balance as of December 31, 2011	$ 1,525	$ 672	$ 229	$2,426

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

	Hedge funds	Private equity	Real estate	Total
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	—	—	—	—
Balance as of December 31, 2011	$ 157	$ 1	$ 7	$ 165

	Hedge funds	Private equity	Real estate	Total
Pension Assets				
Balance as of January 1, 2010	$ —	$ 450	$ 156	$ 606
Actual return on plan assets:				
Relating to assets still held at the reporting date	14	37	13	64
Purchases, sales and settlements:				
Purchases	315	67	14	396
Sales	—	—	(4)	(4)
Settlements	—	(18)	—	(18)
Transfers into (out of) Level 3	—	—	—	—
Balance as of December 31, 2010	$ 329	$ 536	$ 179	$1,044
Other Postretirement Benefits				
Balance as of January 1, 2010	$ —	$ —	$ —	$ —
Actual return on plan assets:				
Relating to assets still held at the reporting date	—	—	2	2
Purchases, sales and settlements:				
Purchases	5	—	2	7
Sales	—	—	—	—
Settlements	—	—	—	—
Transfers into (out of) Level 3 [(a)]	—	—	4	4
Balance as of December 31, 2010	$ 5	$ —	$ 8	$ 13

(a) Commingled fund investments determined to be illiquid during the year were transferred into Level 3.

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 and 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 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, 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. To draw parallels from the trading and quoting of fixed income securities with similar features, pricing services consider various characteristics including the issuer, maturity, purpose of loan, collateral attributes, prepayment speeds, interest rates and credit ratings in order to properly value these securities.

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 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 net asset value per share (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 and a fund level gate. Since these restrictions may limit Exelon's ability to redeem the investments at the measurement date, the hedge fund investments are classified as Level 3.

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

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, real estate funds have been categorized as Level 3.

Defined Contribution Savings Plan (Exelon, Generation, ComEd and PECO)

Exelon, Generation, ComEd and PECO 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 and PECO 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, 2011, 2010 and 2009:

For the Year Ended December 31,	Exelon	Generation	ComEd	PECO
2011	$ 78	$ 40	$ 22	$ 9
2010	81	42	22	9
2009	70	36	20	8

14. Corporate Restructuring and Plant Retirements (Exelon, Generation, ComEd and PECO)

The Registrants provide severance and health and welfare benefits to terminated employees primarily based upon each individual employee's years of service and compensation level. The Registrants accrue amounts associated with severance benefits that are considered probable and that can be reasonably estimated.

The following tables present severance benefits expenses, recorded as operating and maintenance expense in relation to the announced job reductions, for the years ended December 31, 2011, 2010 and 2009:

For the Year Ended December 31,	Generation	ComEd	PECO	Other	Exelon
2011 − Plant retirements	$ 4	$ —	$ —	$ —	$ 4
2010 − Plant retirements	4	—	—	—	4
2009 − Plant retirements	7	—	—	—	7
2009 − Corporate restructuring (a)(b)	11	19	3	1	34

(a) The amounts above include $7 million, $4 million, and $2 million at Generation, ComEd and PECO, respectively, for amounts billed through intercompany allocations for the year ended December 31, 2009.

(b) The severance benefits costs include $1 million of stock compensation expense collectively at Generation and ComEd for which the obligation is recorded in equity for the year ended December 31, 2009. Severance benefits also include $4 million and $2 million at Exelon and ComEd, respectively, of contractual termination benefits expense for which the obligation is recorded in other postretirement benefits.

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

Corporate restructuring (Exelon, Generation, ComEd and PECO). In June 2009, Exelon announced a restructured senior executive team and major spending cuts, including the elimination of approximately 500 employee positions. Exelon eliminated approximately 400 corporate support positions, mostly located at corporate headquarters, and 100 management level positions at ComEd, the majority of which was completed by September 30, 2009. These actions were in response to the continuing economic challenges confronting all parts of Exelon's business and industry especially in light of the commodity−driven nature of Generation's markets, necessitating continued focus on cost management through enhanced efficiency and productivity.

Exelon recorded a pre−tax charge for estimated salary continuance and health and welfare severance benefits of $40 million in June 2009 as a result of the planned job reductions. Subsequent to June 2009, Exelon recorded a net pre−tax credit of approximately $6 million, which included a $10 million reduction in estimated salary continuance and health and welfare severance benefits, offset by $4 million of expense for contractual termination benefits. Cash payments under the plan began in July 2009 and were completed as of December 31, 2011.

The following table presents the activity of severance obligations for the corporate restructuring from January 1, 2010 through December 31, 2011, excluding obligations recorded in equity:

Severance Benefits Obligation	Generation	ComEd	PECO	Other	Exelon
Balance at January 1, 2010	$ 3	$ 7	$ 1	$ 8	$ 19
Cash payments	(3)	(7)	(1)	(7)	(18)
Balance at December 31, 2010	—	—	—	1	1
Cash payments	—	—	—	(1)	(1)
Balance at December 31, 2011	$ —	$ —	$ —	$ —	$ —

Plant Retirements (Exelon and Generation). 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. See Note 18 for additional information regarding the closure of Oyster Creek.

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 will retire 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 began operating under the reliability−must−run agreement effective June 1, 2011.

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

In connection with the retirement of all four units, Exelon is eliminating 253 employee positions, the majority of which are located at the units to be retired. Total expected costs for Generation related to the announced retirements is $37 million, which includes $14 million for estimated salary continuance and health and welfare severance benefits, a $17 million write down of inventory and $6 million of shut down costs. Cash payments under this plan began in January 2010 and will continue through 2013.

Since the announced retirements in December 2009, Generation recorded pre−tax expense of $32 million, which included a $13 million charge for estimated salary continuance and health and welfare severance benefits, $17 million of expense for the write down of inventory and $2 million of shut down costs recorded within operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations.

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. During the year ended December 31, 2010, Generation recorded a net $3 million charge which is primarily due to an increase in estimated salary continuance and health and welfare severance benefits.

The following table presents the activity of severance obligations for the announced Cromby and Eddystone retirements from January 1, 2010 through December 31, 2011:

Severance Benefits Obligation	Exelon and Generation
Balance at January 1, 2010	$ 7
Severance charges recorded	4
Cash payments	(1)
Other adjustments	(3)
Balance at December 31, 2010	7
Severance charges recorded	4
Cash payments	(4)
Balance at December 31, 2011	$ 7

15. Preferred Securities (Exelon, ComEd and PECO)

At December 31, 2011 and 2010, 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, 2011 and 2010, 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.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

At December 31, 2011 and 2010, 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.

	Redemption Price (a)	December 31, 2011 Shares Outstanding	December 31, 2010 Shares Outstanding	December 31, 2011 Dollar Amount	December 31, 2010 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.

16. Common Stock (Exelon, Generation, ComEd and PECO)

At December 31, 2011 and 2010, Exelon's common stock without par value consisted of 2,000,000,000 shares authorized and 663,368,958 shares and 661,845,411, shares outstanding, respectively. At December 31, 2011 and 2010, ComEd's common stock with a $12.50 par value consisted of 250,000,000 shares authorized and 127,016,529 shares and 127,016,519 shares outstanding, respectively. At December 31, 2011 and 2010, PECO's common stock without par value consisted of 500,000,000 shares authorized and 170,478,507 shares outstanding.

ComEd had 75,096 and 75,139 warrants outstanding to purchase ComEd common stock at December 31, 2011 and 2010, 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, 2011 and 2010, 25,032 and 25,046 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.

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

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, 2011. During 2011, 2010 and 2009, 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, 2011, there were approximately 24 million shares authorized for issuance under the LTIP. For the years ended December 31, 2011, 2010 and 2009, 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 and PECO 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.

The following table presents the stock−based compensation expense included in Exelon's Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,		
Components of Stock−Based Compensation Expense	**2011**	**2010**	**2009**
Performance share awards	$ 26	$ 6	$ 31
Stock options	8	10	20
Restricted stock units	31	21	26
Other stock−based awards	4	4	4
Total stock−based compensation expense included in operating and maintenance expense	69	41	81
Income tax benefit	(27)	(16)	(32)
Total after−tax stock−based compensation expense	$ 42	$ 25	$ 49

The following table presents stock−based compensation expense (pre−tax) for the years ended December 31, 2011, 2010 and 2009:

	Year Ended December 31,		
Subsidiaries	**2011**	**2010**	**2009**
Generation	$ 31	$ 21	$ 38
ComEd	5	3	4
PECO	5	3	6
BSC (a)	28	14	33
Total	$ 69	$ 41	$ 81

(a) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations.

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

There were no significant stock−based compensation costs capitalized during the years ended December 31, 2011, 2010 and 2009.

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, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Realized tax benefit when exercised/distributed:			
Stock options	$ 2	$ 5	$ 6
Restricted stock units	8	9	7
Performance share awards	7	13	19
Stock deferral plan	1	1	1
Excess tax benefits included in other financing activities of Exelon's Consolidated Statements of Cash Flows:			
Stock options	$ 1	$ 3	$ 4

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 2011, 2010 and 2009 were not significant.

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

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, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Dividend yield	4.84%	4.56%	3.72%
Expected volatility	24.40%	27.10%	36.70%
Risk−free interest rate	2.65%	2.96%	2.01%
Expected life (years)	6.25	6.25	6.25
Weighted average grant date fair value (per share)	$ 6.22	$ 8.08	$14.43

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, 2011:

	Shares	Weighted Average Exercise Price (per share)	Weighted Average Remaining Contractual Life (years)	Aggregate Intrinsic Value
Balance of shares outstanding at December 31, 2010	11,209,003	$ 48.39		
Options granted	1,017,000	43.40		
Options exercised	(424,228)	30.25		
Options forfeited	(68,175)	49.82		
Options expired	(179,839)	55.68		
Balance of shares outstanding at December 31, 2011	11,553,761	$ 48.49	4.64	$ 30
Exercisable at December 31, 2011 [(a)]	10,676,711	$ 48.48	4.34	$ 30

(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, 2011, 2010 and 2009:

	Year Ended December 31,		
	2011	2010	2009
Intrinsic value [(a)]	$ 5	$ 13	$ 15
Cash received for exercise price	13	24	20

(a) The difference between the market value on the date of exercise and the option exercise price.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

The following table summarizes Exelon's nonvested stock option activity for the year ended December 31, 2011:

	Shares	Weighted Average Exercise Price (per share)
Nonvested at December 31, 2010 [(a)]	942,525	$ 54.35
Granted [(b)]	1,017,000	43.40
Vested [(b)]	(902,636)	47.27
Forfeited	(179,839)	55.68
Nonvested at December 31, 2011 [(a)]	877,050	$ 48.66

(a) Excludes 1,348,000 and 1,209,225 of stock options issued to retirement−eligible employees as of December 31, 2011 and December 31, 2010, respectively, as they are fully vested.
(b) Includes 620,800 of stock options issued to retirement−eligible employees in 2011 that vested immediately upon the employee reaching retirement eligibility.

At December 31, 2011, $3 million of total unrecognized compensation costs related to nonvested stock options are expected to be recognized over the remaining weighted−average period of 2.09 years.

Restricted Stock Units

Exelon grants restricted stock units under the LTIP. The majority of Exelon's restricted stock units will be settled in common stock. In accordance with the authoritative guidance for share−based payments, the cost of services received from employees in exchange for the issuance of restricted stock units to be settled in stock is required to be measured based on the grant date fair value of the restricted stock unit issued. On a very limited basis, Exelon has granted restricted stock units to certain ComEd executives that will be settled in cash. The obligations related to these restricted stock units have been classified as liabilities on Exelon's Consolidated Balance Sheets and are remeasured each reporting period throughout the requisite service period.

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, 2011:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2010 [(a)]	791,820	$ 57.95
Granted	1,015,706	43.33
Vested	(337,970)	60.22
Forfeited	(53,099)	53.16
Undistributed vested awards [(b)]	(341,973)	44.03
Nonvested at December 31, 2011 [(a)]	1,074,484	$ 48.08

(a) Excludes 448,827 and 233,794 of restricted stock units issued to retirement−eligible employees as of December 31, 2011 and December 31, 2010, respectively, as they are fully vested.
(b) Represents restricted stock units that vested but were not distributed to retirement−eligible employees during 2011.

The weighted average grant date fair value (per share) of restricted stock units granted for the years ended December 31, 2011, 2010 and 2009 was $43.33, $44.23 and $56.08, respectively. At December 31, 2011 and 2010, Exelon had obligations related to outstanding restricted stock units not yet settled of $46 million and $38 million, respectively, which are included in common stock in Exelon's Consolidated Balance Sheets. In addition, Exelon had obligations related to outstanding restricted stock units that will be settled in cash of $1 million at December 31, 2011 and 2010, which are included in deferred credits and other liabilities in Exelon's Consolidated Balance Sheets. For the years ended December 31, 2011, 2010 and 2009, Exelon settled restricted stock units with fair value totaling $19 million, $22 million and $17 million, respectively. At December 31, 2011, $26 million of total unrecognized compensation costs related to nonvested restricted stock units are expected to be recognized over the remaining weighted−average period of 2.12 years.

Performance Share Awards

Exelon grants performance share awards under the LTIP. In 2011, the number of performance shares granted was determined based on the measurement of Exelon's operating performance against a set of pre−defined strategic goals through the end of the year of grant. The 2011 performance share awards will be settled entirely in stock over the three year vesting term. These performance share awards are recorded as common stock within the Consolidated Balance Sheets and are recorded at fair value at the date of grant. The grant date fair value of these equity classified performance share awards was estimated based on the expected payout of the award, which may range from 75% to 125% of the payout target. The portion of the award pertaining to the 75% payout floor is valued based on Exelon's stock price on the grant date. The expected payout in excess of the 75% floor is remeasured each reporting period based on Exelon's current stock price and changes in the expected payout of the award; therefore this portion of the award is subject to volatility until the payout is established.

In 2010 and 2009, 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 and 2009 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 years ended December 31, 2010 and 2009 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 and 2009 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 years ended December 31, 2010 and 2009 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.

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

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, 2011:

	Shares	Weighted Average Grant Date Fair Value (per share)
Nonvested at December 31, 2010 [(a)]	214,823	$ 63.51
Granted	689,997	43.52
Vested	(155,132)	66.47
Forfeited	(14,914)	46.01
Undistributed vested awards [(b)]	(387,926)	43.66
Nonvested at December 31, 2011 [(a)]	346,848	$ 45.37

(a) Excludes 455,418 and 234,419 of performance share awards issued to retirement−eligible employees as of December 31, 2011 and December 31, 2010, respectively, as they are fully vested.
(b) Represents performance share awards that vested but were not distributed to retirement−eligible employees during 2011.

The weighted average grant date fair value (per share) of performance share awards granted during the years ended December 31, 2011, 2010 and 2009 was $43.52, $60.82 and $57.34, respectively. During the years ended December 31, 2011, 2010 and 2009, Exelon settled performance shares with a fair value totaling $22 million, $32 million and $47 million, respectively, of which $10 million, $20 million and $30 million was paid in cash, respectively. As of December 31, 2011, $5 million of total unrecognized compensation costs related to nonvested performance shares are expected to be recognized over the remaining weighted−average period of 2 years.

The following table presents the balance sheet classification of obligations related to outstanding performance share awards not yet settled:

	December 31, 2011	December 31, 2010
Current liabilities [(a)]	$ 3	$ 9
Deferred credits and other liabilities [(b)]	—	4
Common stock	30	16
Total	$ 33	$ 29

(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.

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

Table of Contents

17. Earnings Per Share and Equity (Exelon)

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,		
	2011	2010	2009
Net income	$2,495	$2,563	$2,707
Weighted average common shares outstanding—basic	663	661	659
Assumed exercise and/or distributions of stock−based awards	2	2	3
Weighted average common shares outstanding—diluted	665	663	662

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 9 million in 2011, 8 million in 2010 and 5 million in 2009.

18. Commitments and Contingencies (Exelon, Generation, ComEd and PECO)

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, 2011, 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, 2012, 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 $2.0 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 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 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. 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, the current maximum aggregate annual retrospective premium obligation for Generation is approximately $219 million.

NEIL provides 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. 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 $175 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 $44 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.

In addition, Generation participates in the Master Worker Program, which provides coverage for worker tort claims filed for bodily injury caused by a nuclear energy accident. This program was modified, effective January 1, 1998, to provide coverage to all workers whose "nuclear−related employment" began on or after the commencement date of reactor operations. Generation will not be liable for a retrospective assessment under this policy.

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. In January 2009, the DOE issued its Draft National Transportation Plan for the proposed repository. The DOE's press statement accompanying the release of the plan indicated that shipments to the repository are not expected to begin before 2020.

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. Debate surrounding any new strategy likely will address centralized interim storage, permanent storage at multiple sites and/or SNF reprocessing. In early 2010, Secretary of Energy Steven Chu appointed the Blue Ribbon Commission 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. John W. Rowe, Exelon's Chairman and Chief Executive Officer, is one of 15 members of the Commission. 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. Implementation of the BRC's recommendations will require action by both the Administration and Congress.

Given the full implementation of the BRC's recommendations will require action by both the Administration and Congress, it is uncertain whether interim storage facilities or permanent disposal facilities will be operational by 2020. Because there is no particular date before or after 2020 that Generation can establish as having a higher probability as the start date for facility operations, Generation uses the 2020 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, 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 2025 and to 2035 and determined that Generation's aggregate nuclear ARO would be increased by approximately $150 million and $250 million, respectively. 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, 2011, totaling approximately $562 million ($473 million after considering amounts due to co−owners of certain nuclear stations and to the former owner of Oyster Creek). As of December 31, 2011, the amount of SNF storage costs for which reimbursement will be requested from the DOE under the settlement agreement is $54 million, which is recorded within accounts receivable, other. Of this amount, $4 million represents amounts owed to the co−owners of the Peach Bottom and Quad Cities generating facilities.

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, 2011, the unfunded SNF liability for the one−time fee with interest was $1,019 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, 2011, was 0.025%. 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 8—Fair Value of Assets and Liabilities for additional information.

Energy Commitments

Generation's wholesale operations include the physical delivery and marketing of power obtained through its generation capacity, and long−, intermediate− and short−term contracts. Generation maintains a net positive supply of energy and capacity, through ownership of generation assets and power purchase and lease agreements, to protect it from the potential operational failure of one of its owned or contracted power generating units. 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. Generation primarily uses financial contracts in its wholesale marketing activities for hedging purposes. Generation also uses financial contracts to manage the risk surrounding trading for profit activities.

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

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 wholesale market participants who primarily focus on the resale of energy products for delivery. Generation provides delivery of its energy to these customers through rights for firm transmission.

At December 31, 2011, Generation's short− and long−term commitments, relating to the purchase from and sale to unaffiliated utilities and others of energy, capacity and transmission rights, are as indicated in the following tables:

	Net Capacity Purchases (a)	Power Only Purchases (b)	Power Only Sales	Transmission Rights Purchases (c)
2012	$ 177	$ 11	$ 1,150	$ 9
2013	71	—	834	6
2014	63	—	346	—
2015	61	—	200	—
2016	61	—	177	—
Thereafter	478	—	737	—
Total	$ 911	$ 11	$ 3,444	$ 15

(a) Net capacity purchases include PPAs and other capacity contracts that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at December 31, 2011. Expected payments include certain capacity charges which are contingent on plant availability.
(b) Excludes renewable energy PPA contracts 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 is to commence June 1, 2012 and 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 2—Regulatory Matters for further information.

PECO's long−term PPA with Generation, under which PECO obtained all of its electric supply from Generation over the past 12 years, expired on December 31, 2010. During 2009, 2010 and 2011, 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 2—Regulatory Matters for further information regarding the DSP Program.

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 and electric consumption reductions established by the AEPS Act and Act 129, respectively. PECO has entered into contracts with curtailment service providers as part of its EE&C plan in attempt to comply with electric load reduction targets in the top 100 peak hours, during the summer months of June 2012 through September 2012. See Note 2—Regulatory Matters for additional information relating to electric generation procurement, alternative energy resources and energy efficiency programs.

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

ComEd's and PECO's electric supply procurement, curtailment services and REC and AEC purchase commitments as of December 31, 2011 are as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
ComEd							
Electric supply procurement	$ 678	$ 207	$ 292	$ 179	$ —	$ —	$ —
RECs	1	1	—	—	—	—	—
Long−term renewable energy and associated RECs (a)	1,692	36	70	72	73	80	1,361
PECO							
Electric supply procurement	1,088	760	244	59	25	—	—
AECs	39	7	11	9	2	2	8
Curtailment services	13	13	—	—	—	—	—

(a) 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 2 of Combined Notes to Consolidated Financial Statements 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) and PECO has commitments to purchase natural gas, related transportation, storage capacity and services to serve customers in their gas distribution service territory. As of December 31, 2011, these net commitments were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Generation	$8,211	$1,317	$925	$1,010	$1,066	$717	$ 3,176
PECO	511	174	86	71	53	34	93

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

Commercial Commitments

Exelon's commercial commitments as of December 31, 2011, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Letters of credit (non−debt) [a]	$ 952	$ 267	$ —	$ —	$ 685	$ —	$ —
Surety bonds [b]	74	10	—	—	1	6	57
Performance guarantees [c]	533	135	96	200	—	—	102
Energy marketing contract guarantees [d]	280	216	31	3	—	—	30
Nuclear insurance premiums [e]	2,217	—	—	—	—	—	2,217
Lease guarantees [f]	55	—	3	—	—	—	52
2007 City of Chicago Settlement [g]	2	2	—	—	—	—	—
Midwest Generation Capacity Reservation Agreement guarantee [h]	2	2	—	—	—	—	—
Total commercial commitments	$ 4,115	$ 632	$ 130	$ 203	$ 686	$ 6	$ 2,458

(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. As of December 31, 2011, guarantees of $1 million have been issued to provide support for certain letters of credit as required 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.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.
(e) 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.
(f) Lease guarantees—Guarantees issued to ensure payments on building leases.
(g) 2007 City of Chicago Settlement—In December 2007, ComEd entered into an agreement with the City of Chicago. Under the terms of the agreement, ComEd will pay $55 million over six years, of which $53 million was paid through December 31, 2011.
(h) Midwest Generation Capacity Reservation Agreement guarantee—In connection with ComEd's agreement with the City of Chicago entered into on February 20, 2003, Midwest Generation assumed from the City of Chicago a Capacity Reservation Agreement that the City of Chicago had entered into with Calumet Energy Team, LLC. ComEd has agreed to reimburse the City of Chicago for any nonperformance by Midwest Generation under the Capacity Reservation Agreement.

Exelon's commercial commitments shown above as of December 31, 2011 do not reflect the package of benefits of more than $1 billion proposed as part of the application for approval of the merger. See Note 3—Merger and Acquisitions for additional information on the proposed merger with Constellation.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation's commercial commitments as of December 31, 2011, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Letters of credit (non−debt) (a)	$ 901	$ 216	$ —	$ —	$ 685	$ —	$ —
Surety bonds (b)	3	—	—	—	—	—	3
Performance guarantees (c)	533	135	96	200	—	—	102
Energy marketing contract guarantees (d)	280	216	31	3	—	—	30
Nuclear insurance premiums (e)	2,217	—	—	—	—	—	2,217
Total commercial commitments	$ 3,934	$ 567	$ 127	$ 203	$ 685	$ —	$ 2,352

(a) Letters of credit (non−debt)—Non−debt letters of credit maintained to provide credit support for certain transactions as requested by third parties. Guarantees of $1 million have been issued to provide support for certain letters of credit as required 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.
(d) Energy marketing contract guarantees—Guarantees issued to ensure performance under energy commodity contracts.
(e) 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 Nuclear Insurance section within this note for additional details on Generation's nuclear insurance premiums.

ComEd's commercial commitments as of December 31, 2011, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Letters of credit (non−debt) (a)	$ 23	$ 23	$ —	$ —	$ —	$ —	$ —
2007 City of Chicago Settlement (b)	2	2	—	—	—	—	—
Midwest Generation Capacity Reservation Agreement guarantee (c)	2	2	—	—	—	—	—
Surety bonds (d)	5	5	—	—	—	—	—
Total commercial commitments	$ 32	$ 32	$ —	$ —	$ —	$ —	$ —

(a) Letters of credit (non−debt)—ComEd maintains non−debt letters of credit to provide credit support for certain transactions as requested by third parties.
(b) 2007 City of Chicago Settlement—In December 2007, ComEd entered into an agreement with the City of Chicago. Under the terms of the agreement, ComEd will pay $55 million over six years, of which $53 million was paid through December 31, 2011.
(c) Midwest Generation Capacity Reservation Agreement guarantee—In connection with ComEd's agreement with the City of Chicago entered into on February 20, 2003, Midwest Generation assumed from the City of Chicago a Capacity Reservation Agreement that the City of Chicago had entered into with Calumet Energy Team, LLC. ComEd has agreed to reimburse the City of Chicago for any nonperformance by Midwest Generation under the Capacity Reservation Agreement.
(d) Surety bonds—Guarantees issued related to contract and commercial agreements, excluding bid bonds.

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

PECO's commercial commitments as of December 31, 2011, representing commitments potentially triggered by future events, were as follows:

		Expiration within					
	Total	2012	2013	2014	2015	2016	2017 and beyond
Letters of credit (non−debt) (a)	$ 21	$ 21	$ —	$ —	$ —	$ —	$ —
Surety bonds (b)	3	3	—	—	—	—	—
Total commercial commitments	$ 24	$ 24	$ —	$ —	$ —	$ —	$ —

(a) Letters of credit (non−debt)—PECO maintains 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.

Construction Commitments

Generation has committed to the construction of a solar PV facility in Los Angeles County, California. Generation's estimated commitments are $539 million and $374 million for the years 2012 and 2013, respectively. See Note 3—Merger and Acquisitions for additional information.

Refer to Note 2—Regulatory Matters for information on investment programs associated with regulatory mandates such as ComEd's Infrastructure Investment Plan under EIMA and PECO's Smart Meter Procurement and Installation Plan.

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, 2011 were:

	Exelon	Generation	ComEd (b)	PECO (b)
2012	$ 65	$ 29	$ 15	$ 14
2013	59	27	14	14
2014	56	27	12	13
2015	45	27	11	3
2016	47	27	12	3
Remaining years	387	295	61	—
Total minimum future lease payments	$ 659(a)	$ 432(a)	$ 125	$ 47

(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, ComEd and PECO have excluded these payments from the Remaining years, as such amounts would not be meaningful. ComEd's annual obligation for these arrangements, included in each of the years 2012 – 2016, was $1 million. PECO's annual obligation for these agreements, included in each of the years 2012—2013, was $2 million, and in the years 2014 – 2016 was $3 million.

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

The following table presents the Registrants' rental expense under operating leases for the years ended December 31, 2011, 2010 and 2009:

For the Year Ended December 31,	Exelon	Generation (a)	ComEd	PECO
2011	$ 711	$ 659	$ 18	$ 28
2010	722	665	19	31
2009	691	637	21	27

(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 $630 million, $641 million and $616 million during 2011, 2010 and 2009, respectively.

For information regarding capital lease obligations, see Note 10—Debt and Credit Agreements.

Indemnifications Related to Sale of Sithe (Exelon and Generation)

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).

In connection with the sale, Generation recorded liabilities related to certain indemnifications provided to Dynegy and other guarantees directly resulting from the transaction. 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, 2011.

Indemnifications Related to Sale of TEG and TEP (Exelon and Generation)

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. Generation 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 by 2014.

Environmental Matters

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

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

ComEd and PECO have identified 42 and 27 sites, respectively, where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, ComEd or PECO is one of several PRPs that may be responsible for ultimate remediation of each location. Of the 42 sites identified by ComEd, the Illinois EPA or U.S. EPA have approved the cleanup of 13 sites and of the 27 sites identified by PECO, the PA DEP has approved the cleanup of 16 sites. Of the remaining sites identified by ComEd and PECO, 27 and 11 sites, respectively, are currently under some degree of active study and/or remediation. ComEd and PECO anticipate that the majority of the remediation at these sites will continue through at least 2016 and 2019, respectively.

Pursuant to orders from the ICC and PAPUC, respectively, ComEd and PECO 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. During the third quarter of 2011, ComEd and PECO each completed an annual study 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 $14 million and $7 million, respectively. See Note 2—Regulatory Matters for additional information regarding the associated regulatory assets.

As of December 31, 2011 and 2010, the Registrants have accrued the following undiscounted amounts for environmental liabilities in other deferred credits and other liabilities within their Consolidated Balance Sheets:

December 31, 2011	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 224	$ 168
Generation	47	—
ComEd	127	121
PECO	50	47

December 31, 2010	Total environmental investigation and remediation reserve	Portion of total related to MGP investigation and remediation
Exelon	$ 179	$ 156
Generation	15	—
ComEd	120	114
PECO	44	42

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water

Section 316(b) of the Clean Water Act. Section 316(b) requires that the cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state−level NPDES permit programs. All of

Generation's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed−cycle recirculating systems (e.g., cooling towers) are potentially most affected. Those facilities are Clinton, Cromby, Dresden, Eddystone, Fairless Hills, Handley, Mountain Creek, Oyster Creek, Peach Bottom, Quad Cities, Salem and Schuylkill.

On March 28, 2011, the 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 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. Pursuant to a court approved Settlement Agreement, the EPA is required to approve the final rule by July 27, 2012. 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 issued a final NPDES permit to be 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 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 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.

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 generating facilities and its future results of operations, cash flows and financial position.

Alleged Conemaugh Clean Streams Violation by PA DEP. The PA DEP has alleged that GenOn Northeast Management Company, the operator of Conemaugh Generating Station (CGS), violated the Clean Streams Law. GenOn is engaged in discussions with PA DEP and the Company anticipates that the parties will reach a settlement pursuant to which GenOn will be obligated to pay a civil penalty of $500,000, of which Generation's responsibility would be approximately $100,000.

Conemaugh Station Water Discharge Violations. In April 2007, two environmental groups brought a Clean Water Act citizen suit against the operator of CGS, seeking civil penalties and injunctive relief for alleged violations of CGS's NPDES permit. On March 21, 2011, the court entered a partial summary judgment in the plaintiffs' favor, declaring as a matter of law that discharges from CGS had violated the NPDES permit. On June 6, 2011, the operator of CGS signed and entered with the court a settlement and consent decree with the plaintiffs. Under the consent decree, CGS will pay a total of $5 million, of which Generation's share is $1 million.

Air

Cross−State Air Pollution Rule. 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 6, 2010, the U.S. EPA published the proposed Transport Rule as the replacement to the CAIR. On July 7, 2011, the U.S. EPA published the final rule, now known as the Cross−State Air Pollution Rule (CSAPR). The CSAPR requires 27 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. The final rule maintains the January 1, 2012 and January 1, 2014 phase−in dates that were in the proposed Transport Rule. However, the CSAPR imposes tighter emissions caps than the proposed Transport Rule and includes six additional states under the summertime NO_x reduction requirements. These emissions limits may be further reduced as the U.S. EPA finalizes more restrictive ozone and particulate matter NAAQS in the 2012−2013 timeframe.

Under the CSAPR, Generation units will receive allowances based on historic heat input. Intrastate, and limited interstate, trading of allowances is permitted, subject to certain limitations. The CSAPR restricts 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 are not expected to be used by Generation's fossil−fuel power plants and that have 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, 2011, Generation had $4 million of emission allowances carried at the lower of weighted average cost or market. Numerous entities have challenged the CSAPR in the D.C. Circuit Court, and some have requested a stay of the rule pending the D.C. Circuit Court's consideration of the matter on the merits. Exelon believes that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the Clean Air Act. The D.C. Circuit Court has granted permission for Exelon, as well as a number of other parties, to intervene in the litigation in support of the rule and in opposition to a stay of the rule. The D.C. Circuit Court has not set a case management schedule, and it is therefore unknown when the litigation will be resolved.

On October 14, 2011, the EPA proposed for public comment certain technical corrections to CSAPR, including correction of data errors in determining generation unit allowances and state allowance budgets. These corrections will increase the number of emission allowances available under the CSAPR. In addition, the proposal defers until 2014 penalties that will involve surrender of additional allowances should states not meet certain levels of emission reductions. This deferral is intended to increase the liquidity of allowances during the initial years of transition from CAIR to CSAPR.

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. Subsequently the Court ordered an expedited briefing schedule that requires that final briefs be submitted by March 16, 2012, and scheduled oral argument for April 13, 2012. It is unknown when the Court will issue its decision on the merits. Exelon believes that the CSAPR is a valid exercise of the U.S. EPA's authority and discretion under the Clean Air Act. The D.C. Circuit Court has granted permission for Exelon, as well as a number of other parties, to intervene in the litigation in support of the rule.

EPA Mercury and Air Toxics Standards (MATS). In March 2005, the U.S. EPA finalized the CAMR, which was a national program to cap mercury emissions from fossil−fuel−fired electric utility steam generating units (EGUs) starting in 2010, with a second reduction in the mercury emission cap level scheduled for 2018. The D.C. Circuit Court later vacated the CAMR on the basis that the U.S. EPA had failed to properly de−list mercury as a HAP under Section 112(c)(1) of the Clean Air Act. The result of this decision is that mercury emissions from EGUs are subject to the more stringent requirements of maximum achievable control technology applicable to HAPs. In resolution of the CAMR litigation, the U.S. EPA entered into a Consent Decree that required it to propose by March 16, 2011 HAP regulations for emissions from fossil generating stations, and to publish final HAP regulations by November 15, 2011.

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 new source performance standards for EGUs. The final rule, known as the Mercury and Air Toxics (MATS) rule, requires coal−fired electric generation plants 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, with specific guidelines for an additional one or two years in limited cases. The rule will be effective 60 days after it is published in the Federal Register in early 2012. 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.

The U.S. EPA previously announced that it would complete a review of NAAQS in the 2011 – 2012 timeframe for particulate matter, nitrogen dioxide, sulfur dioxide, and lead. This review could result in more stringent emissions limits on fossil−fired electric generating stations. In September 2011, the U.S. EPA withdrew its reconsideration of the NAAQS standard for ozone, which is next scheduled for reconsideration in 2013.

In addition, as of December 31, 2011, Exelon has a $656 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 HAP 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.

Notices and Finding of Violations Related to Electric Generation Stations. On August 6, 2007, ComEd received a NOV, addressed to it and Midwest Generation, LLC (Midwest Generation) from the U.S. EPA, alleging that ComEd and Midwest Generation have violated and are continuing to violate several 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 1999.

The generating stations are currently owned and operated by Midwest Generation, which purchased the stations in December 1999 from ComEd. Under the terms of the sale agreement, Midwest Generation and its affiliate, Edison Mission Energy (EME), assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance of the stations with environmental laws before the purchase of the stations 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 August 2009, the DOJ and the Illinois Attorney General filed a complaint against Midwest Generation with the U.S. District Court for the Northern District of Illinois initiating enforcement proceedings with respect to the alleged Clean Air Act violations set forth in the NOV. Neither ComEd nor Exelon were 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 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 substantially similar to 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 U.S. District Court granted ComEd's motion to dismiss the May 2010 complaint. On January 3, 2012, upon leave of the U.S. District Court, the government parties appealed the dismissal of ComEd to the U.S. Circuit Court of Appeals.

In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business. Exelon, Generation and ComEd are unable to predict the ultimate resolution of the claims alleged in the amended complaint, the costs that might be incurred or the amount of indemnity that may be available from Midwest Generation and EME; however, Exelon, Generation and ComEd have concluded that in light of the District Court's decision the likelihood of loss is remote. Therefore, no reserve has been established. Further, Generation believes that it would be reimbursed by Midwest Generation and EME for any losses under the terms of the indemnification agreement, subject to the credit worthiness of Midwest Generation and EME.

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 Bridgeton, 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 excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the EPA for review. It is anticipated that the EPA will propose a remedy in the first quarter of 2012, which will be subject to public comment. Thereafter the EPA will select a final remedy and enter into a Consent Decree with the PRP's to effectuate the remedy. An 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 the use of an 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 1967 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 $100 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2012 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.

Climate Change Regulation. Exelon is subject to climate change regulation or legislation at the international, 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 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. Under the 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. Exelon could be significantly affected by the regulations if it were to build new plants or modify existing plants.

Litigation and Regulatory Matters

Exelon and Generation

Asbestos Personal Injury Claims. 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. Legal costs are charged to operating and maintenance expense as incurred.

At December 31, 2011 and 2010, Generation had reserved approximately $49 million and $53 million, respectively, in total for asbestos−related bodily injury claims. As of December 31, 2011, approximately $14 million of this amount related to 180 open claims presented to Generation, while the remaining $35 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 2011, 2010 and 2009, the updates to this reserve did not result in material adjustments.

Exelon

Savings Plan Claim. On September 11, 2006, five individuals claiming to be participants in the Exelon Corporation Employee Savings Plan, Plan #003 (Savings Plan), filed a putative class action lawsuit in the U.S. District Court for the Northern District of Illinois. The complaint names as defendants Exelon, its Director of Employee Benefit Plans and Programs, the Employee Savings Plan Investment Committee, the Compensation and the Risk Oversight Committees of Exelon's Board of Directors and members of those committees. On December 9, 2009, the District Court granted the defendants' motion to dismiss the amended complaint and enter judgment in favor of the defendants. The plaintiffs appealed the District Court's dismissal of their claims to the U.S. Court of Appeals for the Seventh Circuit who affirmed the dismissal of the class action lawsuit on September 6, 2011.

General. The Registrants are 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. The Registrants maintain 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.

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, 2011, such capital was $2.9 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.

Continuous Power Interruption

Illinois law 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) 30,000 or more 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. ComEd does not believe that during the years 2011, 2010 and 2009 it had any interruptions that have triggered this damage liability or reimbursement requirement.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable under provisions of the Illinois Public Utilities Act that could require damage compensation to customers in connection with the July 11, 2011 storm system that affected more than 900,000 customers in ComEd’s service territory, as well as five other storm systems that affected ComEd’s customers during June and July 2011. 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 which those customers are located could seek recovery of emergency and contingency expenses. On January 27, 2012, the ICC Staff and the Illinois Attorney General filed testimony in the ICC proceeding. They both disagree with ComEd's interpretation that the statute does not apply to the 2011 storms. Additionally, the ICC witness supports granting a waiver for three of the six storms, while the Attorney General asserts that ComEd should be held responsible for the damages from all of the storms. ComEd is continuing to assess its position relative to its request and is scheduled to file responsive testimony during the first quarter of 2012. The ultimate outcome of this proceeding is uncertain, and the amount of damages, if any, that might be asserted cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows. Additional active proceedings related to storms of lesser collective impact are also pending.

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

Income Taxes

See Note 11—Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

19. Supplemental Financial Information (Exelon, Generation, ComEd and PECO)

Supplemental Income Statement Information

The following tables provide additional information about the Registrants' Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Operating revenues [a]				
Wholesale	$ 7,717	$ 8,837	$ —	$ 32
Retail electric and gas	10,323	1,407(b)	5,460	3,463
Other	884	64(c)	596	225
Total operating revenues	$18,924	$ 10,308	$6,056	$3,720

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Operating revenues [a]				
Wholesale	$ 5,934	$ 8,986	$ —	$ 44
Retail electric and gas	11,906	1,004(b)	5,648	5,262
Other	804	35(c)	556	213
Total operating revenues	$18,644	$ 10,025	$6,204	$5,519

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Operating revenues [a]				
Wholesale	$ 5,469	$ 8,905	$ —	$ 26
Retail electric and gas	11,099	838(b)	5,220	5,049
Other	750	(40)(c)	554	236
Total operating revenues	$17,318	$ 9,703	$5,774	$5,311

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) Includes operating revenues from affiliates.
(b) Generation's retail electric and gas operating revenues consist primarily of Exelon Energy Company, LLC. Generation's retail electric operating revenues are allocated among its reportable segments.
(c) Includes amounts recorded related to the Illinois Settlement Legislation.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Depreciation, amortization and accretion				
Property, plant and equipment	$1,284	$ 570	$ 502	$ 191
Regulatory assets	51	—	40	11
Nuclear fuel [(a)]	755	755	—	—
ARO accretion [(b)]	214	214	—	—
Total depreciation, amortization and accretion	$2,304	$ 1,539	$ 542	$ 202

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Depreciation, amortization and accretion				
Property, plant and equipment	$1,144	$ 474	$ 473	$ 171
Regulatory assets [(c)]	931	—	43	889
Nuclear fuel [(a)]	672	672	—	—
ARO accretion [(b)]	196	195	1	—
Total depreciation, amortization and accretion	$2,943	$ 1,341	$ 517	$1,060

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Depreciation, amortization and accretion				
Property, plant and equipment	$ 996	$ 333	$ 446	$ 162
Regulatory assets [(c)]	838	—	48	790
Nuclear fuel [(a)]	558	558	—	—
ARO accretion [(b)]	209	207	1	—
Total depreciation, amortization and accretion	$2,601	$ 1,098	$ 495	$ 952

(a) Included in fuel expense on the Registrants' Consolidated Statements of Operations.
(b) Included in operating and maintenance expense on the Registrants' Consolidated Statements of Operations.
(c) For PECO, primarily reflects CTC amortization.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Taxes other than income				
Utility [(a)]	$ 443	$ 27	$ 243	$173
Real estate	177	146	22	9
Payroll	123	71	25	13
Other	42	20	6	10
Total taxes other than income	$ 785	$ 264	$ 296	$205

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Taxes other than income				
Utility [(a)]	$ 476	$ —	$ 205	$271
Real estate	175	142	20	13
Payroll	121	70	24	12
Other	36	18	7	7
Total taxes other than income	$ 808	$ 230	$ 256	$303

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Taxes other than income				
Utility[a]	$ 481	$ —	$ 232	$ 249
Real estate	157	127	20	10
Payroll	114	65	23	12
Other	26	13	6	5
Total taxes other than income	$ 778	$ 205	$ 281	$ 276

(a) Generation's utility tax represents gross receipts tax related to its retail operations and ComEd's and PECO'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 the Registrants' Consolidated Statements of Operations.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Loss in equity method investments				
NuStart Energy Development, LLC	(1)	(1)	—	—
Total loss in equity method investments	$ (1)	$ (1)	$ —	$ —

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Loss in equity method investments				
NuStart Energy Development, LLC	—	—	—	—
Total loss in equity method investments	$ —	$ —	$ —	$ —

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Loss in equity method investments				
Financing trusts	$ (24)	$ —	$ —	$ (24)
NuStart Energy Development, LLC	(3)	(3)	—	—
Total loss in equity method investments	$ (27)	$ (3)	$ —	$ (24)

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Other, Net				
Decommissioning-related activities:				
Net realized income on decommissioning trust funds[a]—				
Regulatory Agreement Units	$ 177	$ 177	$ —	$ —
Non-Regulatory Agreement Units	45	45	—	—
Net unrealized losses on decommissioning trust funds—				
Regulatory Agreement Units	(74)	(74)	—	—
Non-Regulatory Agreement Units	(4)	(4)	—	—
Net unrealized gains on pledged assets—				
Zion Station decommissioning	48	48	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(130)	(130)	—	—
Total decommissioning-related activities	62	62	—	—
Investment income	10	1	1	3
Long-term lease income	28	—	—	—
Interest income related to uncertain income tax positions	53	31	14	1
AFUDC-Equity	17	—	8	9
Bargain purchase gain related to Wolf Hollow acquisition	36	36	—	—
Other	(7)	(8)	6	1
Other, net	$ 199	$ 122	$ 29	$ 14

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

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Other, Net				
Decommissioning−related activities:				
Net realized income on decommissioning trust funds [(a)] —				
Regulatory Agreement Units	$ 176	$ 176	$ —	$ —
Non−Regulatory Agreement Units	51	51	—	—
Net unrealized gains on decommissioning trust funds—				
Regulatory Agreement Units	316	316	—	—
Non−Regulatory Agreement Units	104	104	—	—
Regulatory offset to decommissioning trust fund−related activities [(b)]	(394)	(394)	—	—
Total decommissioning−related activities	253	253	—	—
Investment income	1	—	—	1
Long−term lease income	27	—	—	—
Interest income related to uncertain income tax positions	—	—	6	—
AFUDC−Equity	11	—	4	7
Realized gains on Rabbi trust investments	1	—	1	—
Other	19	4	13	—
Other, net	$ 312	$ 257	$ 24	$ 8

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Other, Net				
Decommissioning−related activities:				
Net realized income on decommissioning trust funds [(a)] —				
Regulatory Agreement Units	$ 126	$ 126	$ —	$ —
Non−Regulatory Agreement Units	29	29	—	—
Net unrealized gains on decommissioning trust funds—				
Regulatory Agreement Units	801	801	—	—
Non−Regulatory Agreement Units	227	227	—	—
Regulatory offset to decommissioning trust fund−related activities [(b)]	(746)	(746)	—	—
Total decommissioning−related activities	437	437	—	—
Investment income	5	—	1	4
Long−term lease income	26	—	—	—
Interest income related to uncertain income tax positions [(c)]	50	—	65	5
AFUDC−Equity	9	—	5	4
Realized gain on Rabbi trust investments	5	—	5	—
Other−than−temporary impairment to Rabbi trust investments [(d)]	(7)	—	(7)	—
Losses on early retirement of debt	(117)	(71)	—	—
Other	19	10	10	—
Other, net	$ 427	$ 376	$ 79	$ 13

(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 12—Asset Retirement Obligations for additional information regarding the accounting for nuclear decommissioning.

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

(c) Primarily includes interest income at ComEd from the 2009 re−measurement of income tax uncertainties. See Note 11—Income Taxes for additional information.
(d) ComEd recorded an other−than−temporary impairment to Rabbi trust investments during 2009.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009.

For the Year Ended December 31, 2011	Exelon	Generation	ComEd	PECO
Cash paid (refunded) during the year:				
Interest (net of amount capitalized)	$ 649	$ 158	$ 296	$ 128
Income taxes (net of refunds)	(457)	347	(676)	(65)
Other non−cash operating activities:				
Pension and non−pension postretirement benefit costs	$ 542	$ 249	$ 213	$ 32
Provision for uncollectible accounts	121	—	57	64
Stock−based compensation costs	67	—	—	—
Other decommissioning−related activity (a)	16	16	—	—
Energy−related options (b)	137	137	—	—
Amortization of regulatory asset related to debt costs	21	—	18	3
Uncollectible accounts recovery, net	14	—	14	—
Discrete impacts from 2010 Rate Case order (c)	(32)	—	(32)	—
Bargain purchase gain related to Wolf Hollow Acquisition	(36)	(36)	—	—
Discrete impacts from Energy Infrastructure Modernization Act (EIMA) (d)	(82)	—	(82)	—
Other	14	55	8	1
Total other non−cash operating activities	$ 782	$ 421	$ 196	$ 100
Changes in other assets and liabilities:				
Under/over−recovered energy and transmission costs	$ (45)	$ —	$ (49)	$ 4
Other current assets	(101)	(23)	(14)	(15)
Other noncurrent assets and liabilities	126	(34)	108	25
Total changes in other assets and liabilities	$ (20)	$ (57)	$ 45	$ 14

	Exelon	Generation	ComEd	PECO
Non−cash investing and financing activities:				
Change in ARC	$ 186	$ 186	$ —	$ —
Change in capital expenditures not paid	96	125 (e)	7	(35)

(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 12—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 2—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 2—Regulatory Matters for more information.
(e) Includes $120 million of capital expenditures not paid as of December 31, 2011 related to Antelope Valley.

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

For the Year Ended December 31, 2010	Exelon	Generation	ComEd	PECO
Cash paid (refunded) during the year:				
Interest (net of amount capitalized)	$ 665[(a)]	$ 145	$ 283	$ 168
Income taxes (net of refunds)	1,219	732	15	433
Other non−cash operating activities:				
Pension and non−pension postretirement benefit costs	$ 581	$ 268	$ 215	$ 46
Provision for uncollectible accounts	108	1	48	59
Provision for obsolete inventory	12	12	—	—
Stock−based compensation costs	44	—	—	—
Other decommissioning−related activity [(b)]	(91)	(91)	—	—
Energy−related options [(c)]	(73)	(73)	—	—
ARO adjustment	(19)	(8)	(10)	(1)
Amortization of regulatory asset related to debt costs	24	—	20	4
Accrual for Illinois utility distribution tax refund [(d)]	(25)	—	(25)	—
Under−recovered uncollectible accounts, net [(e)]	(14)	—	(14)	—
ARP SO2 allowances impairment	57	57	—	—
Other	5	16	4	—
Total other non−cash operating activities	$ 609	$ 182	$ 238	$ 108
Changes in other assets and liabilities:				
Under/over−recovered energy and transmission costs	$ 61	$ —	$ 58	$ 3
Other current assets	(18)	(16)	12	(19)
Other noncurrent assets and liabilities	(99)	(29)	(203)[(f)]	94
Total changes in other assets and liabilities	$ (56)	$ (45)	$ (133)	$ 78

	Exelon	Generation	ComEd	PECO
Non−cash investing and financing activities:				
Change in ARC	$ (428)	$ (428)	$ —	$ —
Change in capital expenditures not paid	34	13	7	14
Purchase accounting adjustments	9	9	—	—
Exelon Wind acquisition [(g)]	32	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 11—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 12—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 undercollections associated with 2010 activity. ComEd is recovering these costs through a rider mechanism authorized by the ICC. See Note 2—Regulatory Matters for additional information regarding the Illinois legislation for recovery of uncollectible accounts.
(f) Relates primarily to a decrease in interest payable associated with a change in uncertain income tax positions. See Note 11—Income Taxes for additional information.
(g) Represents contingent liability recorded in connection with the December 9, 2010 acquisition of Exelon Wind. See Note 3—Acquisition for additional information.

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

For the Year Ended December 31, 2009	Exelon	Generation	ComEd	PECO
Cash paid (refunded) during the year:				
Interest (net of amount capitalized)	$ 647	$ 69	$ 284	$ 179
Income taxes (net of refunds)	982	668	63	368
Other non−cash operating activities:				
Pension and non−pension postretirement benefit costs	$ 536	$ 240	$ 192	$ 47
Loss in equity method investments	27	3	—	24
Provision for uncollectible accounts	149	2	85	63
Stock−based compensation costs	70	—	—	—
Other decommissioning−related activity (a)	(163)	(163)	—	—
Energy−related options (b)	46	46	—	—
ARO adjustment (c)	(47)	(47)		
Amortization of regulatory liability related to debt costs	25	—	21	4
Amortization of the regulatory liability related to the PURTA tax settlement	(2)	—	—	(2)
Other−than−temporary impairment to Rabbi trust impairments (d)	7	—	7	—
Inventory write−down related to plant retirements	17	17	—	—
Other	(13)	6	4	5
Total other non−cash operating activities	$ 652	$ 104	$ 309	$ 141
Changes in other assets and liabilities:				
Under/over−recovered energy and transmission costs	$ 23	$ —	$ 13	$ 10
Other current assets	(2)	—	—	3
Other noncurrent assets and liabilities	(134)	(1)	(76) (e)	(47)
Total changes in other assets and liabilities	$ (113)	$ (1)	$ (63)	$ (34)

	Exelon	Generation	ComEd	PECO
Non−cash investing and financing activities:				
Change in ARC	$ 67	$ 67	$ —	$ —
Change in capital expenditures not paid	70	97	37	4
Purchase accounting adjustments	9	9	—	—

(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 12—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) Represents the reduction in the ARO in excess of the existing ARC balances for Generation's nuclear generating units that are not subject to regulatory agreement with respect to decommissioning trust funding (the former AmerGen units and the portions of the Peach Bottom units).
(d) ComEd recorded an other−than−temporary impairment to Rabbi trust investments during the second quarter of 2009. See Note 8—Fair Value of Assets and Liabilities for additional information regarding the impairment.
(e) Relates primarily to a decrease in interest payable associated with the remeasurement of uncertain income tax positions. See Note 11—Income Taxes for additional information.

DOE Smart Grid Investment Grant (Exelon and PECO). For the years ended December 31, 2011 and December 31, 2010, Exelon and PECO have included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $51 million and $28 million, respectively, and reimbursements of $56 million in 2011 related to PECO's DOE SGIG. See Note 2—Regulatory Matters for additional information regarding the accounting for the DOE SGIG.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Supplemental Balance Sheet Information

The following tables provide additional information about assets and liabilities of the Registrants at December 31, 2011 and 2010.

December 31, 2011	Exelon	Generation	ComEd	PECO
Investments				
Equity method investments:				
Financing trusts (a)	$ 15	$ —	$ 6	$ 8
Keystone Fuels, LLC	13	13	—	—
Conemaugh Fuels, LLC	16	16	—	—
Sacramento Solar	1	1	—	—
Total equity method investments	45	30	6	8
Other investments:				
Net investment in direct financing leases	656	—	—	—
Employee benefit trusts and investments (b)	65	11	21	22
Total investments	$ 766	$ 41	$ 27	$ 30

December 31, 2010	Exelon	Generation	ComEd	PECO
Investments				
Equity method investments:				
Financing trusts (a)	$ 15	$ —	$ 6	$ 8
Keystone Fuels, LLC	10	10	—	—
Conemaugh Fuels, LLC	13	13	—	—
NuStart Energy Development, LLC	1	1	—	—
Total equity method investments	39	24	6	8
Other investments:				
Net investment in direct financing leases	629	—	—	—
Employee benefit trusts and investments (b)	64	11	23	20
Total investments	$ 732	$ 35	$ 29	$ 28

(a) Includes investments in financing trusts, which were not consolidated within the financial statements of Exelon. See Note 1—Significant Accounting Policies for additional information.
(b) The Registrants' investments in these marketable securities are recorded at fair market value.

December 2010 IRS Payment (Exelon). 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 11—Income Taxes for additional information.

Like−Kind Exchange Transaction (Exelon). 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, 2011 and 2010, the components of the net investment in long−term leases were as follows:

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

	December 31,	
	2011	2010
Estimated residual value of leased assets	$1,492	$1,492
Less: unearned income	836	863
Net investment in long−term leases	$ 656	$ 629

The following tables provide additional information about liabilities of the Registrants at December 31, 2011 and 2010.

December 31, 2011	Exelon	Generation	ComEd	PECO
Accrued expenses				
Compensation−related accruals (a)	$ 520	$ 264	$ 127	$ 48
Taxes accrued	297	241	59	5
Interest accrued	192	56	124	27
Severance accrued	15	9	2	1
Other accrued expenses	231(b)	209(b)	6	2
Total accrued expenses	$1,255	$ 779	$ 318	$ 83

December 31, 2010	Exelon	Generation	ComEd	PECO
Accrued expenses				
Compensation−related accruals (a)	$ 465	$ 229	$ 110	$ 51
Taxes accrued	297	38	83	9
Interest accrued	195	76	154	30
Severance accrued	22	10	4	1
Other accrued expenses	61	38	15	4
Total accrued expenses	$1,040	$ 391	$ 366	$ 95

(a) Primarily includes accrued payroll, bonuses and other incentives, vacation and benefits.
(b) Includes $184 million for amounts accrued related to Antelope Valley.

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

The following tables provide information about accumulated OCI (loss) recorded (after tax) within Exelon's Consolidated Balance Sheets at December 31, 2011 and 2010:

December 31, 2011	Exelon	Generation	ComEd	PECO
Accumulated other comprehensive income (loss)				
Net unrealized gain on cash flow hedges	$ 488	$ 915	$ —	$ —
Pension and non−pension postretirement benefit plans	(2,938)	—	—	—
Unrealized loss on marketable securities	—	—	(1)	—
Total accumulated other comprehensive income (loss)	$ (2,450)	$ 915	$ (1)	$ —

December 31, 2010	Exelon	Generation	ComEd	PECO
Accumulated other comprehensive income (loss)				
Net unrealized gain on cash flow hedges	$ 400	$ 1,013	$ —	$ —
Pension and non−pension postretirement benefit plans	(2,823)	—	—	—
Unrealized loss on marketable securities	—	—	(1)	—
Total accumulated other comprehensive income (loss)	$ (2,423)	$ 1,013	$ (1)	$ —

20. Segment Information (Exelon, Generation, ComEd and PECO)

Exelon has five reportable segments, which include Generation's three reportable segments consisting of the Mid−Atlantic, Midwest, and South and West, and ComEd and PECO.

Mid−Atlantic represents Generation's operations primarily in Pennsylvania, New Jersey and Maryland; Midwest includes the operations in Illinois, Indiana, Michigan and Minnesota; and the South and West includes operations primarily in Texas, Georgia, Oklahoma, Kansas, Missouri, Idaho and Oregon. Generation's retail gas, proprietary trading, other revenues and mark−to−market activities have not been allocated to a segment.

Exelon and Generation evaluate the performance of Generation's power marketing activities in Mid−Atlantic, Midwest, and South and West 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 and PECO. Purchased power costs include all costs associated with the procurement 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. Generation's retail gas, proprietary trading, compensation under the reliability−must−run rate schedule, other revenues and mark−to−market activities are not allocated to a region. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

ComEd and PECO each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon evaluates the performance of ComEd and PECO based on net income.

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

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements follows:

	Generation (a)	ComEd	PECO	Other	Intersegment Eliminations	Consolidated
Operating revenues [b]:						
2011	$ 10,308	$ 6,056	$3,720	$ 830	$ (1,990)	$ 18,924
2010	10,025	6,204	5,519	755	(3,859)	18,644
2009	9,703	5,774	5,311	757	(4,227)	17,318
Intersegment revenues [c]:						
2011	$ 1,161	$ 2	$ 5	$ 831	$ (1,990)	$ 9
2010	3,102	2	5	756	(3,859)	6
2009	3,472	2	6	756	(4,227)	9
Depreciation and amortization						
2011	$ 570	$ 542	$ 202	$ 21	$ —	$ 1,335
2010	474	516	1,060	25	—	2,075
2009	333	494	952	55	—	1,834
Operating expenses [b]:						
2011	$ 7,432	$ 5,074	$3,065	$ 863	$ (1,990)	$ 14,444
2010	6,979	5,148	4,858	792	(3,859)	13,918
2009	6,408	4,931	4,614	840	(4,225)	12,568
Interest expense, net:						
2011	$ 170	$ 345	$ 134	$ 77	$ —	$ 726
2010	153	386	193	85	—	817
2009	113	319	187	112	—	731
Income (loss) before income taxes:						
2011	$ 2,827	$ 666	$ 535	$ (63)	$ (13)	$ 3,952
2010	3,150	694	476	(91)	(8)	4,221
2009	3,555	603	499	(235)	(3)	4,419
Income taxes:						
2011	$ 1,056	$ 250	$ 146	$ 9	$ (4)	$ 1,457
2010	1,178	357	152	(27)	(2)	1,658
2009	1,433	229	146	(102)	6	1,712
Net income (loss):						
2011	$ 1,771	$ 416	$ 389	$ (72)	$ (9)	$ 2,495
2010	1,972	337	324	(64)	(6)	2,563
2009	2,122	374	353	(133)	(9)	2,707
Capital expenditures:						
2011	$ 2,491	$ 1,028	$ 481	$ 42	$ —	$ 4,042
2010	1,883	962	545	14	(78)[d]	3,326
2009	1,977	854	388	54	—	3,273
Total assets:						
2011	$ 27,433	$22,653	$9,156	$6,244	$ (10,394)	$ 55,092
2010	24,534	21,652	8,985	6,651	(9,582)	52,240

(a) Generation represents the three segments, Mid−Atlantic, Midwest, and South and West as shown below. Intersegment revenues for the years ended December 31, 2011, 2010 and 2009 represent Mid−Atlantic revenue from sales to PECO of $508 million, $2,092 million and $2,016 million, respectively, and Midwest revenue from sales to ComEd of $653 million, $1,010 million and $1,456 million, respectively.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(b) For the years ended December 31, 2011, 2010 and 2009, utility taxes of $243 million, $205 million and $232 million, respectively, are included in revenues and expenses for ComEd. For the years ended December 31, 2011, 2010 and 2009, utility taxes of $173 million, $271 million and $249 million, respectively, are included in revenues and expenses for PECO.
(c) 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 2—Regulatory Matters for additional information on AECs. For Exelon, these amounts are included in operating revenues in the Consolidated Statements of Operations.
(d) 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.

	Mid−Atlantic	Midwest	South and West	Other [b]	Generation
Total revenues [a]:					
2011	$ 3,967	$ 5,344	$ 776	$ 221	$ 10,308
2010	3,246	5,762	692	325	10,025
2009	3,195	5,538	714	256	9,703
Revenues net of purchased power and fuel expense:					
2011 [c]	$ 3,359	$ 3,547	$ 70	$ (118)	$ 6,858
2010	2,512	4,081	(131)	100	6,562
2009	2,578	4,148	(117)	162	6,771

(a) Includes all sales to third parties and affiliated sales to ComEd and PECO. For the years ended December 31, 2011, 2010 and 2009, there were no transactions among Generation's reportable segments which would result in intersegment revenue for Generation.
(b) Includes retail gas, proprietary trading, other revenue and mark−to−market activities as well as amounts paid related to the Illinois Settlement Legislation.
(c) In 2010, Other also includes the $57 million lower of cost or market impairment for the ARP SO_2 allowances further described in Note 18—Commitments and Contingencies.

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

21. Related Party Transactions (Exelon, Generation, ComEd and PECO)

Exelon

The financial statements of Exelon include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2011	2010	2009
Operating revenues from affiliates:			
PETT [(a)]	$ —	$ —	$ 3
PECO [(b)]	9	6	9
Total operating revenues from affiliates	$ 9	$ 6	$ 12
Fuel purchases from related parties:			
Keystone Fuels, LLC	$ 68	$ 74	$ 56
Conemaugh Fuels, LLC	69	70	69
Total fuel purchases from related parties	$ 137	$ 144	$ 125
Charitable contribution to Exelon Foundation [(c)]	$ —	$ 10	$ 10
Interest expense to affiliates, net:			
ComEd Financing III	$ 13	$ 13	$ 13
PETT [(a)]	—	—	51
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
Other	—	—	1
Total interest expense to affiliates, net	$ 25	$ 25	$ 77
Loss in equity method investments:			
PETT [(a)]	$ —	$ —	$ (24)
NuStart Energy Development, LLC	(1)	—	(3)
Total loss in equity method investments	$ (1)	$ —	$ (27)

	December 31,	
	2011	2010
Investments in affiliates:		
ComEd Financing III	$ 6	$ 6
PECO Energy Capital Corporation	4	4
PECO Trust IV	5	5
Total investments in affiliates	$ 15	$ 15
Payables to affiliates (current):		
ComEd Financing III	$ 4	$ 4
PECO Trust III	1	1
Total payables to affiliates (current)	$ 5	$ 5
Long−term debt to financing trusts (including due within one year):		
ComEd Financing III	$ 206	$ 206
PECO Trust III	81	81
PECO Trust IV	103	103
Total long−term debt due to financing trusts	$ 390	$ 390

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) 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. See Note 1—Significant Accounting Policies for additional information. PETT was liquidated and dissolved upon repayment of the debt in September 2010.
(b) 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 2—Regulatory Matters for additional information.
(c) 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.

Transactions involving Generation, ComEd and PECO are further described in the tables below.

Generation

The financial statements of Generation include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2011	2010	2009
Operating revenues from affiliates:			
ComEd [a]	$ 653	$1,010	$1,456
PECO [b]	508	2,092	2,016
Total operating revenues from affiliates	$1,161	$3,102	$3,472
Fuel purchases from related parties:			
PECO	$ 1	$ 1	$ 1
Keystone Fuels, LLC	68	74	56
Conemaugh Fuels, LLC	69	70	69
Total fuel purchases from related parties	$ 138	$ 145	$ 126
Operating and maintenance from affiliates:			
ComEd [c]	$ 2	$ 2	$ 2
PECO [c]	5	4	6
BSC [d]	314	285	298
Total operating and maintenance from affiliates	$ 321	$ 291	$ 306
Loss in equity method investments			
NuStart Energy Development, LLC	$ (1)	$ —	$ (3)
Cash distribution paid to member	$ 172	$1,508	$2,276
Contribution from member	$ 30	$ 62	$ 57

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

Table of Contents

	December 31, 2011	December 31, 2010
Mark−to−market derivative assets with affiliates (current):		
ComEd (e)	$ 503	$ 450
PECO (i)	—	5
Total mark−to−market derivative assets with affiliates (current)	$ 503	$ 455
Receivables from affiliates (current):		
ComEd (a)(f)(g)	$ 70	$ 58
PECO (b)	39	248
Total receivables from affiliates (current)	$ 109	$ 306
Receivable from affiliate (noncurrent)		
Exelon	$ 1	$ 1
Mark−to−market derivative assets with affiliates (noncurrent):		
ComEd (e)	$ 191	$ 525
Payables to affiliates (current):		
Exelon (h)	$ 7	$ 6
BSC (d)	51	41
Total payables to affiliates (current)	$ 58	$ 47
Payables to affiliates (noncurrent):		
ComEd (j)	$1,857	$1,892
PECO (j)	365	375
Total payables to affiliates (noncurrent)	$2,222	$2,267

(a) Generation has an ICC−approved RFP contract with ComEd to provide a portion of ComEd's electricity supply requirements. Generation also sells RECs to ComEd. In addition, Generation had revenue from ComEd associated with the settled portion of the financial swap contract established as part of the Illinois Settlement. See Note 2—Regulatory Matters for additional information.
(b) Generation had a PPA with PECO, to provide the full energy requirements to PECO through 2010. In addition, Generation has five−year and ten−year agreements with PECO to sell non−solar and solar AECs, respectively. See Note 2—Regulatory Matters for additional information.
(c) Generation requires electricity for its own use at its generating stations. Generation purchases electricity and distribution and transmission services from PECO and only distribution and transmission services from ComEd for the delivery of electricity to its generating stations.
(d) Generation receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(e) Represents the fair value of Generation's five−year financial swap contract with ComEd.
(f) Under the Illinois Settlement Legislation, Generation is responsible to contribute to rate relief programs for ComEd customers, which are issued through ComEd. At December 31, 2010, Generation had a $1 million payable, which is netted against the receivable from ComEd. See Note 2—Regulatory Matters for additional information.
(g) Generation had a $53 million and $40 million receivable from ComEd at December 31, 2011 and 2010, respectively, associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement. See Note 2—Regulatory Matters and Note 9 − Derivative Financial Instruments for additional information.
(h) In order to facilitate payment processing, Exelon processes certain invoice payments on behalf of Generation.
(i) Represents the fair value of Generation's block contracts with PECO.

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

(j) Generation has long−term payables to ComEd and PECO as a result of the nuclear decommissioning contractual construct whereby, to the extent NDT funds are greater than the underlying ARO at the end of decommissioning, such amounts are due back to ComEd and PECO, as applicable, for payment to their respective customers. See Note 12—Asset Retirement Obligations.

ComEd

The financial statements of ComEd include related party transactions as presented in the tables below:

	For the Years Ended December 31, 2011	2010	2009
Operating revenues from affiliates			
Generation	$ 2	$ 2	$ 2
Purchased power from affiliate			
Generation [a]	$653	$1,010	$1,456
Operating and maintenance from affiliate			
BSC [b]	$158	$ 152	$ 165
Interest expense to affiliates, net:			
Exelon	$ 2	$ —	$ —
ComEd Financing III	13	13	13
Total interest expense to affiliates, net	$ 15	$ 13	$ 13
Capitalized costs			
BSC [b]	$ 85	$ 84	$ 72
Cash dividends paid to parent	$300	$ 310	$ 240
Contribution from parent	$ 11	$ 2	$ 8

	December 31, 2011	2010
Prepaid voluntary employee beneficiary association trust [c]	$ 12	$ 7
Investment in affiliate		
ComEd Financing III	$ 6	$ 6
Receivable from affiliates (noncurrent):		
Generation [d]	$1,857	$1,892
Other	3	3
Total receivable from affiliates (noncurrent)	$1,860	$1,895
Payables to affiliates (current):		
Generation [a][e][f]	$ 70	$ 58
BSC [b]	35	33
Exelon [g]	—	302
ComEd Financing III	4	4
Other	2	1
Total payables to affiliates (current)	$ 111	$ 398
Mark−to−market derivative liability with affiliate (current)		
Generation [h]	$ 503	$ 450
Mark−to−market derivative liability with affiliate (noncurrent)		
Generation [h]	$ 191	$ 525
Long−term debt to ComEd financing trust		
ComEd Financing III	$ 206	$ 206

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

(a) ComEd procures a portion of its electricity supply requirements from Generation under an ICC−approved RFP contract. ComEd also purchases RECs from Generation. In addition, purchased power expense includes the settled portion of the financial swap contract with Generation established as part of the Illinois Settlement Legislation. See Note 2—Regulatory Matters and Note 9—Derivative Financial Instruments for additional information.
(b) ComEd receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(c) The voluntary employee benefit association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for ComEd's contributions to the plans, being higher than actual claim expense incurred by the plans over time. The prepayment is included in other current assets.
(d) ComEd has a long−term receivable from Generation as a result of the nuclear decommissioning contractual construct for generating facilities previously owned by ComEd. To the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to ComEd for payment to ComEd's customers.
(e) ComEd had a $53 million and $40 million payable to Generation at December 31, 2011 and 2010, respectively, associated with the completed portion of the financial swap contract entered into as part of the Illinois Settlement Legislation. See Note 2—Regulatory Matters and Note 9—Derivative Financial Information for additional information.
(f) Under the Illinois Settlement Legislation, Generation is responsible to contribute to rate relief programs for ComEd customers, which are issued through ComEd. At December 31, 2010, ComEd had a $1 million receivable, which is netted against the payable to Generation. See Note 2—Regulatory Matters for additional information.
(g) Under the Tax Sharing Agreement, Exelon made a payment to the IRS on December 28, 2010. As a result of the payment, ComEd recorded a short−term intercompany note payable to Exelon. ComEd repaid this amount plus interest to Exelon in 2011. See Note 11—Income Taxes for additional information on Exelon's payment to the IRS.
(h) To fulfill a requirement of the Illinois Settlement Legislation, ComEd entered into a five−year financial swap with Generation.

PECO

The financial statements of PECO include related party transactions as presented in the tables below:

	For the Years Ended December 31,		
	2011	2010	2009
Operating revenues from affiliates:			
Generation[(a)]	$ 5	$ 5	$ 6
PETT[(b)(c)]	—	—	3
Total operating revenues from affiliates	$ 5	$ 5	$ 9
Purchased power from affiliate			
Generation[(d)]	$495	$2,085	$2,005
Operating and maintenance from affiliates:			
BSC[(e)]	$ 92	$ 89	$ 94
Generation	4	—	1
Total operating and maintenance from affiliates	$ 96	$ 89	$ 95
Interest expense to affiliates, net:			
PETT[(c)]	$—	$ —	$ 51
PECO Trust III	6	6	6
PECO Trust IV	6	6	6
Total interest expense to affiliates, net	$ 12	$ 12	$ 63
Loss in equity method investments			
PETT[(c)]	$—	$ —	$ (24)
Capitalized costs			
BSC[(e)]	$ 60	$ 40	$ 24
Cash dividends paid to parent	$348	$ 224	$ 312
Repayment of receivable from parent	$—	$ 180	$ 320
Contribution from parent	$ 18	$ 43	$ 27

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

	December 31, 2011	December 31, 2010
Prepaid voluntary employee beneficiary association trust [f]	$ 3	$ 1
Investments in affiliates:		
PECO Energy Capital Corporation	$ 4	$ 4
PECO Trust IV	4	4
Total investments in affiliates	$ 8	$ 8
Receivable from affiliate (noncurrent):		
Generation [g]	$365	$375
Mark−to−market derivative liability with affiliate (current):		
Generation [h]	$—	$ 5
Payables to affiliates (current):		
Generation [d]	$ 39	$248
BSC [e]	21	25
Exelon	1	1
PECO Trust III	1	1
Total payables to affiliates (current)	$ 62	$275
Long−term debt to PETT and other financing trusts (including due within one year):		
PECO Trust III	$ 81	$ 81
PECO Trust IV	103	103
Total long−term debt to financing trusts	$184	$184

(a) PECO provides energy to Generation for Generation's own use.
(b) PECO received a monthly administrative servicing fee from PETT based on a percentage of the outstanding balance of all series of transition bonds.
(c) 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. See Note 1—Significant Accounting Policies for additional information. PETT was liquidated and dissolved upon repayment of the debt in September 2010.
(d) PECO obtained all of its electric supply from Generation through 2010 under a PPA. During 2011, PECO purchased electric supply from Generation under contracts executed through its competitive procurement process. In addition, PECO has five−year and ten−year agreements with Generation to purchase non−solar and solar AECs, respectively. See Note 2—Regulatory Matters for additional information on AECs.
(e) PECO receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead. A portion of such services is capitalized.
(f) The voluntary employee beneficiary association trusts covering active employees are included in corporate operations and are funded by the operating segments. A prepayment to the active welfare plans has accumulated due to actuarially determined contribution rates, which are the basis for PECO's contributions to the plans, being higher than actual claim expense incurred by the plans over time.
(g) PECO has a long−term receivable from Generation as a result of the nuclear decommissioning contractual construct, whereby, to the extent the assets associated with decommissioning are greater than the applicable ARO at the end of decommissioning, such amounts are due back to PECO for payment to PECO's customers.
(h) PECO entered into block contracts with Generation to procure electric generation for its residential procurement class beginning January 1, 2011 in accordance with its PAPUC−approved DSP Program. See Note 9—Derivative Financial Instruments for additional information.

Table of Contents

22. Quarterly Data (Unaudited) (Exelon, Generation, ComEd and PECO)

Exelon

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	
	2011	2010	2011	2010	2011	2010
Quarter ended:						
March 31	$ 5,052	$ 4,461	$1,202	$1,402	$668	$749
June 30	4,587	4,398	1,034	1,018	620	445
September 30	5,295	5,291	1,181	1,367	601	845
December 31	3,991	4,494	1,062	939	606	524

	Average Basic Shares Outstanding (in millions)		Net Income per Basic Share	
	2011	2010	2011	2010
Quarter ended:				
March 31	662	661	$ 1.01	$ 1.13
June 30	663	661	0.93	0.67
September 30	663	662	0.91	1.28
December 31	664	662	0.91	0.79

	Average Diluted Shares Outstanding (in millions)		Net Income per Diluted Share	
	2011	2010	2011	2010
Quarter ended:				
March 31	664	662	$ 1.01	$ 1.13
June 30	664	662	0.93	0.67
September 30	665	663	0.90	1.27
December 31	666	663	0.91	0.79

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

	2011				2010			
	Fourth Quarter	Third Quarter	Second Quarter	First Quarter	Fourth Quarter	Third Quarter	Second Quarter	First Quarter
High price	$45.45	$45.27	$42.89	$43.58	$44.49	$43.32	$45.10	$49.88
Low price	39.93	39.51	39.53	39.06	39.05	37.63	37.24	42.97
Close	43.37	42.61	42.84	41.24	41.64	42.58	37.97	43.81
Dividends	0.525(a)	0.525	0.525	0.525	0.525	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.

Combined Notes to Consolidated Financial Statements—(Continued)
(Dollars in millions, except per share data unless otherwise noted)

Generation

The data shown below includes all adjustments that Generation considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2011	2010	2011	2010	2011	2010
Quarter ended:						
March 31	$ 2,739	$ 2,421	$ 801	$ 916	$ 495	$ 561
June 30	2,546	2,353	647	587	443	382
September 30	2,862	2,655	754	883	386	605
December 31	2,161	2,596	673	660	446	424

ComEd

The data shown below includes all adjustments that ComEd considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income	
	2011	2010	2011	2010	2011	2010
Quarter ended:						
March 31	$ 1,466	$ 1,415	$ 200	$ 291	$ 69	$ 116
June 30	1,444	1,499	254	256	114	9
September 30	1,784	1,918	243	280	112	121
December 31	1,362	1,372	285	229	121	91

PECO

The data shown below includes all adjustments that PECO considers necessary for a fair presentation of such amounts:

	Operating Revenues		Operating Income		Net Income on Common Stock	
	2011	2010	2011	2010	2011	2010
Quarter ended:						
March 31	$ 1,153	$ 1,455	$ 210	$ 194	$ 125	$ 100
June 30	842	1,269	161	182	82	74
September 30	946	1,469	153	215	104	126
December 31	778	1,299	131	70	73	20

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Exelon, Generation, ComEd, and PECO

None.

ITEM 9A. CONTROLS AND PROCEDURES

Exelon, Generation, ComEd and PECO

During the fourth quarter of 2011, each registrant’s management, including its principal executive officer and principal financial officer, evaluated that registrant’s disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in that registrant’s periodic reports that it files with the SEC. These disclosure controls and procedures have been designed by each registrant to ensure that (a) information relating to that registrant, including its consolidated subsidiaries, that is required to be included in filings under the Securities Exchange Act of 1934, is accumulated and made known to that registrant’s management, including its principal executive officer and principal financial officer, by other employees of that registrant and its subsidiaries as appropriate to allow timely decisions regarding required disclosure, and (b) this information is recorded, processed, summarized, evaluated and reported, as applicable, within the time periods specified in the SEC’s rules and forms. Due to the inherent limitations of control systems, not all misstatements may be detected. These inherent limitations include the realities that judgments in decision−making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls could be circumvented by the individual acts of some persons or by collusion of two or more people.

Accordingly, as of December 31, 2011, the principal executive officer and principal financial officer of each registrant concluded that such registrant’s disclosure controls and procedures were effective to accomplish their objectives. Each registrant continually strives to improve its disclosure controls and procedures to enhance the quality of its financial reporting and to maintain dynamic systems that change as conditions warrant. However, there have been no changes in internal control over financial reporting that occurred during the fourth quarter of 2011 that have materially affected, or are reasonably likely to materially affect, Exelon’s internal control over financial reporting.

Exelon, Generation, ComEd and PECO

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2011. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2011 and, therefore, concluded that each registrant’s internal control over financial reporting was effective. Management’s Report on Internal Control Over Financial Reporting is included in ITEM 8. Financial Statements and Supplementary Data.

ITEM 9B. OTHER INFORMATION

Exelon, Generation and ComEd

Anne R. Pramaggiore, President and Chief Operating Officer of ComEd, Michael J. Pacilio, President, Exelon Nuclear and Chief Nuclear Officer, Generation, and Sunil Garg, President, Exelon Power and Senior Vice President, Generation, each entered into a Change in Control Employment

Agreement effective as of February 10, 2011. The terms of these change in control employment agreements are substantially the same as the change in control employment agreements entered into by other senior executives and previously disclosed, except that the agreements with Ms. Pramaggiore and Messrs. Pacilio and Garg do not include excise tax gross−up provisions, consistent with a policy adopted by the compensation committee in April 2009. The form of Change in Control Employment Agreement is attached hereto as Exhibit 10−44.

PECO

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Exelon

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 9, 2012.

Directors, Director Nomination Process, and Audit Committee

The information required under ITEM 10 concerning directors and nominees for election as directors at Exelon's annual meeting of shareholders (Item 401 of Regulation S−K), the director nomination process (Item 407(c)(3)) and the audit committee (Item 407(d)(4) and (d)(5)) is incorporated herein by reference to information to be contained in Exelon's definitive 2012 proxy statement (2012 Exelon Proxy Statement) to be filed with the SEC before April 30, 2012 pursuant to Regulation 14A under the Securities Exchange Act of 1934.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to Exelon's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. The Code of Business Conduct is filed as Exhibit 14 to this report and is available on Exelon's website at *www.exeloncorp.com*. The Code of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Bruce G. Wilson, Senior Vice President, Deputy General Counsel, and Corporate Secretary, Exelon Corporation, P.O. Box 805398, Chicago, Illinois 60680−5398.

If any substantive amendments to the Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Code of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or Corporate Controller, Exelon will disclose the nature of such amendment or waiver on Exelon's website, *www.exeloncorp.com*, or in a report on Form 8−K.

Section 16(a) Beneficial Ownership Reporting Compliance

Based upon signed affirmations received from directors and officers, as well as administrative review of company plans and accounts administered by private brokers on behalf of directors and officers which have been disclosed to Exelon by the individual directors and officers, Exelon believes that its directors and officers made all required filings on a timely basis during 2011, with the exception of one report that the company filed late on behalf of Mr. Hilzinger, which reported the first accrual of deferred compensation shares in 2011, and Mr. Bradford, whose Form 3 and subsequent Form 4 were filed late after he became an executive officer.

Generation

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 9, 2012.

Directors

Generation operates as a limited liability company and has no board of directors.

Audit Committee

Generation is a controlled subsidiary of Exelon and does not have a separate audit committee. Instead, that function is fulfilled by the audit committee of the Exelon board of directors. See discussion of Exelon's audit committee to be incorporated by reference to the 2012 Exelon Proxy Statement.

Code of Ethics

The Exelon Code of Business Conduct is the code of ethics that applies to all officers and employees of Generation. See discussion of Exelon's Code of Ethics above.

If any substantive amendments to Exelon's Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of Exelon's Code of Business Conduct, as applied to Generation's Chief Executive Officer, Chief Financial Officer or Corporate Controller, Generation will cause the nature of such amendment or waiver to be disclosed on Exelon's website, *www.exeloncorp.com*, or in a report on Form 8−K.

ComEd

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 9, 2012.

Directors

Frank M. Clark. Age 66. Chairman and Chief Executive Officer since November 28, 2005. Previously Executive Vice President and Chief of Staff of Exelon and President of ComEd from 2004 to 2005; Senior Vice President, Exelon, and Executive Vice President of Exelon Energy Delivery and President of ComEd from 2003 to 2004. He is a director of Aetna, Inc. (insurance), BMO Financial Corp. (financial services) and Waste Management, Inc. (environmental services). Mr. Clark has worked for ComEd for over forty years and has extensive knowledge of ComEd's business and regulatory matters.

James W. Compton. Age 73. Director of ComEd since September 18, 2006. President and Chief Executive Officer of Chicago Urban League from 1978 through 2006; President and Chief Executive Officer of the Chicago Urban League Development Corporation from 1980 through 2006. Mr. Compton has extensive knowledge of ComEd and its business, having previously served as a director of ComEd from 1989−2000 and having served as a director of a community−based bank. In addition, he is very familiar with ComEd's customers and contributes to ComEd's outreach to diverse groups in Chicago.

A. Steven Crown. Age 60. Director of ComEd since May 9, 2011. A general partner of Henry Crown and Company for more than the past five years. Henry Crown and Company is a private investment group that manages investments in banking, transportation, oil and gas, cellular phones, home furnishings, and resort properties. Mr. Crown has extensive knowledge of the Chicago economy and his experience contributes to his effectiveness as a member of the ComEd board.

Peter V. Fazio, Jr. Age 72. Director of ComEd since October 29, 2007. A partner of the law firm of Schiff Hardin, LLP. A past Chairman, Executive Committee Member and Managing Partner of Schiff Hardin. In addition to his general legal expertise, Mr. Fazio previously served as general counsel of another electric and gas utility and brings the ComEd board knowledge of utility regulatory and legal issues.

Sue L. Gin. Age 70. Director of ComEd since November 28, 2005. Founder, Owner, Chairman and Chief Executive Officer of Flying Food Group, LLC (in−flight catering company). She is also a director of Exelon. Ms. Gin is the first non−French citizen and one of the first women to join the board of Servair, the global Air France catering arm. As a leader in the Chicago business community and as the chief executive of a privately held Chicago−based business, Ms. Gin is familiar with the Chicago economy and the needs of Chicago businesses served by ComEd. As a female member of the Asian−American community, Ms. Gin also brings diversity to the board and contributes to ComEd's diversity initiatives and community outreach.

Edgar D. Jannotta. Age 80. Director of ComEd from November 28, 2005 through January 31, 2012. Chairman of William Blair & Company, L.L.C. (investment banking and brokerage company) since March 2001. He is also a director of Aon Corporation (insurance) and Molex, Inc. (automobile parts) and formerly served as a director of AAR Corporation and Bandag, Incorporated. Mr. Jannotta was a director of ComEd from 1994 to 2000 and a director of Exelon from 2000 through 2007. He is a leader in the Chicago business community and has extensive financial and investment banking experience that gives him knowledge of credit and capital markets and the needs of Chicago businesses served by ComEd.

Edward J. Mooney. Age 70. Director of ComEd from October 16, 2006 through December 31, 2011. From March 2000 to March 2001, was Delegue General−North America of Suez Lyonnaise (private infrastructure services). Mr. Mooney was chairman and chief executive officer of Nalco Chemical Company from 1994 until March 2000. He is also a director of Northern Trust Corporation, FMC Corporation, FMC Technologies, Inc., Cabot Microelectronics Corporation and Polyone Corporation. Mr. Mooney's experience as a CEO and as a director of other corporations, as well as his involvement in the Chicago business community, make him a valuable member of the ComEd board.

Michael H. Moskow. Age 74. Director of ComEd since January 28, 2008. Vice Chairman and a Senior Fellow at the Chicago Council on Global Affairs. President and Chief Executive Officer (CEO) of the Federal Reserve Bank of Chicago from 1994 to 2007. He is also director of Discover Financial Services, Northern Trust Mutual Funds and Taylor Capital Group. Mr. Moskow is a recognized leader in the Chicago business community with knowledge of the economy of the Midwestern United States and the northern Illinois communities ComEd serves. His business experience and service on the boards of other companies and organizations enable him to contribute to the work of the ComEd board.

John W. Rowe. Age 66. Director of ComEd since April 27, 2009. Mr. Rowe has served as Chairman and Chief Executive Officer of Exelon since April of 2002 and he has been a Director of Exelon since its formation in 2000. At various times since 2000 he has also held the title of President of Exelon and from 2000 through April 2002 he was also Co−Chief Executive Officer of Exelon. Mr. Rowe is also a director of PECO and The Northern Trust Company, and formerly served as a director of Sunoco, Inc. from 2003 to December 2011, and UnumProvident Corporation from 1999 (upon the merger of Unum Corporation into Provident Companies, Inc.) to 2005; he had previously served on Unum Corporation Board from 1988, Fleet Boston Financial Corporation (bank) from 1999 (when BankBoston was acquired by Fleet Boston) to 2002 and Wisconsin Central Transportation Corporation from 1998 to 2001 (when it was acquired by Canadian National Railway). Mr. Rowe has an aggregate of over 27 years experience as the CEO of Exelon and other utilities.

Jesse H. Ruiz. Age 46. Director of ComEd since October 16, 2006. Corporate & Securities Partner at the law firm Drinker Biddle & Reath LLP; Resigned as Chairman of the Illinois State Board of Education in May 2011 in order to be appointed Vice President of The Chicago Board of Education, by Mayor Emanuel. Mr. Ruiz's legal and governmental experience in the city and state where ComEd's business is conducted has enabled him to contribute to the ComEd board. Mr. Ruiz contributes to ComEd's outreach to diverse groups.

Richard L. Thomas. Age 81. Director of ComEd from November 28, 2005 through January 31, 2012. Chairman of First Chicago NBD Corporation (banking and financial services) from December 1995 through May 1996 and the First Chicago Corporation from January 1992 through December 1996. Served as a director of Exelon from 2000 through 2007, and also previously as a director of Sara

Lee Corporation, PMI Group, Inc., IMC Global Inc, and The SABRE Group Holdings, Inc. Mr. Thomas was a director of ComEd from 1998 through 2000 and a director of Exelon from 2000 through 2007. Mr. Thomas is a recognized leader in the Chicago business community with knowledge of the markets that ComEd serves. His experience as a CEO and his experience as a director of other companies enable him to contribute to the ComEd board. His experience as a banker and knowledge of the credit and capital markets are valuable to the ComEd board.

Audit Committee

ComEd is a controlled subsidiary of Exelon and does not have a separate audit committee. Instead, that function is fulfilled by the audit committee of the Exelon board of directors. See discussion of Exelon's audit committee to be incorporated by reference to the 2012 Exelon Proxy Statement.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to ComEd's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. See discussion of Exelon's Code of Ethics above.

If any substantive amendments to Exelon's Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of Exelon's Code of Business Conduct, as applied to ComEd's Chief Executive Officer, Chief Financial Officer or Corporate Controller, ComEd will cause the nature of such amendment or waiver to be disclosed on Exelon's website, *www.exeloncorp.com*, or in a report on Form 8−K.

PECO

Executive Officers

The information required by ITEM 10 relating to executive officers is set forth above in ITEM 1. BUSINESS—Executive Officers of the Registrants at February 9, 2012.

Directors

The board is classified into three classes, with two directors in Class I, three directors in Class II and three directors in Class III.

John W. Rowe. Age 66. Class I director. Mr. Rowe has served as Chairman and Chief Executive Officer of Exelon since April of 2002 and he has been a Director of Exelon since its formation in 2000. At various times since 2000 he has also held the title of President of Exelon and from 2000 through April 2002 he was also Co−Chief Executive Officer of Exelon. Mr. Rowe is also a director of ComEd and The Northern Trust Company, and formerly served as a director of Sunoco, Inc. from 2003 to December 2011, and UnumProvident Corporation, from 1999 (upon the merger of Unum Corporation into Provident Companies, Inc.) to 2005; he had previously served on Unum Corporation Board from 1988, Fleet Boston Financial Corporation (bank) from 1999 (when BankBoston was acquired by Fleet Boston) to 2002 and Wisconsin Central Transportation Corporation from 1998 to 2001 (when it was acquired by Canadian National Railway). Mr. Rowe has an aggregate of over 27 years experience as the CEO of Exelon and other utilities.

M. Walter D'Alessio. Age 78. Class II director. Director since July 23, 2007. Senior Managing Director of NorthMarq Advisors, LLC (a real estate consulting group), a position that he has held since July 2003. Vice Chairman of NorthMarq Capital (a real estate investment banking firm) from 2003 to 2011. Chairman and CEO of Legg Mason Real Estate Services, Inc. from 1982 through July 2003. Also Chairman of the Board of Directors of Brandywine Real Estate Investment Trust, where he has been a trustee since 1996, and chair of Independence Blue Cross, where he has been a director since 1991, a director of the Federal Home Loan Bank Board of Pittsburgh from 2008 through 2010, and a director of the Pennsylvania Real Estate Investment Trust since 2005. He is also a director of Exelon. Mr. D'Alessio is a leader in the Philadelphia business community and has knowledge of the greater Philadelphia metropolitan area and economic trends in the region, particularly with respect to real estate development. Mr. D'Alessio contributes to the PECO board through his long history as a business leader and as a director of other business organizations.

Nelson A Diaz. Age 64. Class II director. Director since July 23, 2007. Judge Diaz is a contract partner at Dilworth Paxson LLP, a Philadelphia−based regional law firm, where he serves as Chair of the firm's Diversity Committee. Previously, he was Counsel to Cozen O'Connor, a Philadelphia−based law firm from May 2007 to June 2011 and a partner of the law firm Blank Rome LLP from March 2004 through May 2007 and from February 1997 through December 2001. He also served as City Solicitor of the City of Philadelphia from December 2001 through January 2004 and as General Counsel, United States Department of Housing and Urban Affairs, from 1993 to 1997. He is also a director of Exelon. Judge Diaz's legal and governmental experience at the Federal level and in a city and state where PECO's business is conducted has enabled him to contribute to the board on matters related to Federal, state and local regulation and public policy. In addition, Judge Diaz's Puerto Rican heritage adds diversity to the PECO board. He serves on the boards of the National Association for Hispanic Elderly and he formerly served on the boards of the U.S. Hispanic Leadership Institute and the United States Hispanic Advocacy Association. Judge Diaz serves as Chair of the Corporate Advisory Board of APM, Inc. (Association of Puerto Ricans on the March) in Philadelphia, is on the Board of Trustees for the Philadelphia Museum of Art and is a member of the President's Commission on White House Fellowships. He is active in Philadelphia government and community affairs and neighborhood development and has made contributions to PECO's outreach to diverse groups within Philadelphia and neighboring communities.

Rosemarie B. Greco. Age 65. Class I director. Director since July 23, 2007. Founding principal of GRECOVentures Ltd. (a private management consulting firm). She served as the director of the Governor's Office of Health Care Reform for the Commonwealth of Pennsylvania from January 2003 through December 2008, and the Senior Adviser to the Governor of Pennsylvania−Health Care Reform from January 2009 through December 2010. Formerly President of CoreStates Financial Corporation and former Director, President and CEO of CoreStates Bank, N.A. She served from 1998 through May 2011 as a director of Sunoco, Inc. and served as a trustee of Pennsylvania Real Estate Investment Trust from 1997 through June 2011. She has also served as a trustee of SEI I Mutual Funds, a subsidiary of SEI Investments, Co. since 1999. She is also a director of Exelon. Her experience in the banking industry in Philadelphia has given her insight into the needs of the bank's clients, who are also customers of PECO. Ms. Greco's role as a female executive has brought diversity to PECO's board, and she has contributed to PECO's diversity initiatives. Her experience as a CEO with responsibility for overseeing the quality of operations is a useful background for her work on operational issues at PECO. Ms. Greco's experience as a CEO, a management consultant, and a member of a number of corporate boards contribute to her effectiveness as a member of the PECO board.

Charisse R. Lillie. Age 59. Class II director. Director since January 1, 2010. Vice President of Community Investment for Comcast Corporation and President of the Comcast Foundation since 2008. She served as Vice President of Human Resources for Comcast Corporation and Senior Vice President of Human Resources for Comcast Cable from 2005 to 2008. She was a partner in the law firm of Ballard, Spahr, Andrews & Ingersoll, LLP from January 1992 to February 2005. She also serves on the boards of Howard University, The Franklin Institute Science Museum, the American Arbitration Association, the Penn Mutual Life Insurance Company, the United Way of Southeastern Pennsylvania, and the Pyramid Club. Ms. Lillie's legal and regulatory experience and experience on the boards of other businesses and organizations enable her to contribute to the PECO board. She brings diversity to the PECO board and will contribute to PECO's diversity initiatives.

Denis P. O'Brien. Age 51. Class III director. Director since June 30, 2003. Executive Vice President of Exelon; President and Chief Executive Officer of PECO since August 2007. President of PECO from 2003 to 2007. Mr. O'Brien has spent his entire career in PECO's operations and has extensive knowledge of PECO's business and regulatory matters.

Thomas J. Ridge. Age 66. Class III director. Director since July 23, 2007. President, Ridge Global LLC and strategic limited partner in Doheny Global Group, a U.S.−based international developer of energy facilities. Secretary of the United States Department of Homeland Security from January 2003 through January 2005, and the Assistant to the President for Homeland Security (an Executive Office created by President Bush) from October 2001 through December 2002. He served as Governor of the Commonwealth of Pennsylvania from 1994 through October 2001. He is also a director of Exelon, The Hershey Company (chocolate and sugar confectionary) since 2007, and Brightpoint, Inc. since 2009. He previously served as a director of Home Depot Corporation (home improvement specialty retailer) from 2005 to 2007 and Vonage Holdings Corp. (software technology for voice and messaging services) from 2005 to 2011. Governor Ridge's governmental service at the Federal level and in Pennsylvania is valued by the board. His Department of Homeland Security experience provides valuable insight into issues relating to the security of PECO's transmission and distribution facilities. His service as a director of other companies brings additional perspective to the PECO board, which benefits greatly from Governor Ridge's insights from his experience in state government and his expertise on matters relating to the security of critical infrastructure.

Ronald Rubin. Age 80. Class III director. Director since July 23, 2007. Chairman and Chief Executive Officer of the Pennsylvania Real Estate Investment Trust (a real estate management and development company). Mr. Rubin was a director of PECO from 1988 through 2000 and a director of Exelon from 2000 through 2007. He previously served as a director of Continental Bank and Midlantic Bank. Mr. Rubin is active in the Philadelphia business community and has knowledge of the greater Philadelphia metropolitan area and economic trends in the region, particularly with respect to real estate development. Mr. Rubin contributes to the PECO board through his long history as a business leader and as a director of other business organizations.

Audit Committee

PECO is a controlled subsidiary of Exelon and does not have a separate audit committee. Instead, that function is fulfilled by the audit committee of the Exelon board of directors. See discussion of Exelon's audit committee to be incorporated by reference to the 2012 Exelon Proxy Statement.

Code of Ethics

Exelon's Code of Business Conduct is the code of ethics that applies to PECO's Chief Executive Officer, Chief Financial Officer, Corporate Controller, and other finance organization employees. See discussion of Exelon's Code of Ethics above.

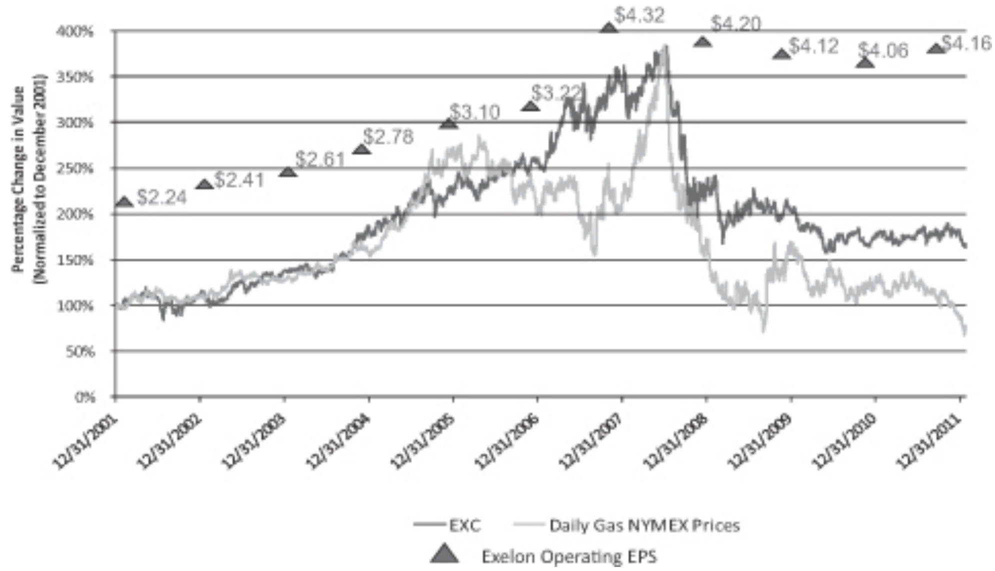
If any substantive amendments to Exelon's Code of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of Exelon's Code of Business Conduct, as applied to PECO's Chief Executive Officer, Chief Financial Officer or Corporate Controller, PECO will cause the nature of such amendment or waiver to be disclosed on Exelon's website, *www.exeloncorp.com*, or in a report on Form 8−K.

ITEM 11. EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

About Exelon

Exelon Corporation is one of the nation's largest electric utility holding companies. Over half of Exelon's more than $19 billion in annual revenues and over two−thirds of Exelon's nearly $2.5 billion in annual net income comes from the competitive electricity generation, wholesale energy marketing and competitive retail supply operations of its subsidiary, Exelon Generation, which has a nationwide reach and strong positions in the Midwest and Mid−Atlantic. The balance comes from the regulated transmission and distribution operations of ComEd and PECO. ComEd distributes electricity to approximately 3.8 million customers in northern Illinois and PECO distributes electricity to approximately 1.6 million customers in southeastern Pennsylvania and natural gas to approximately 494,000 customers in the Philadelphia area. The extent of Exelon's reliance on revenues and profits from the competitive generation, wholesale and retail supply operations of Exelon Generation makes Exelon subject to natural gas commodity prices to a greater extent than many other utilities that rely more heavily on income from their regulated operations; natural gas sets the price for electricity in the competitive market. The graph below shows the high correlation between Exelon's stock price and spot natural gas prices, as well as Exelon's adjusted (non−GAAP) operating earnings. Exelon's earnings have not declined in parallel with the decline in spot natural gas prices because Exelon has a policy to hedge commodity risk on a ratable basis over three−year periods, which is intended to reduce the near−term financial impact of market price volatility. For additional information about Exelon's exposure to commodity risk, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview—*Economic and Market Conditions* and—*Hedging Strategy*. For additional information about adjusted (non−GAAP) operating earnings, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Executive Overview—*Adjusted (non−GAAP) Operating Earnings*. However, Exelon's stock price at any point in time reflects investors' future expectations about natural gas prices and their consequent effect on the price Exelon will be paid for the electricity it produces in the future.



Since 2008, commodity gas prices, which in turn set electricity prices, have been on the decline, and as a result, regulated utilities have outperformed competitive integrated utilities such as Exelon; in fact, Exelon has the largest exposure to natural gas commodity prices among its peers. All of Exelon's generation output is sold in the competitive market while the majority of electric industry peers own their generation in regulated utilities where rates are set through the applicable state regulatory process. In addition, the total shareholder return for a number of Exelon's peer companies that are involved in mergers and acquisitions have outperformed since the announcement of their transactions. As a result, Exelon's one, three and five year total shareholder returns (−2.0%, −6.1%, and −3.5%, respectively) have underperformed relative to its peers. However, taking a longer view, Exelon has achieved 116% total shareholder return since its inception in 2000, which is higher than the 107% total shareholder return of the Philadelphia Utility Sector Index of 20 electric and gas utilities and the 11% total shareholder return of the S&P 500. Despite low commodity prices, Exelon has had strong performance in 2011 and the board of directors is vigilant about continuing investment in human resources and assets and the ability to maintain strong performance to be well positioned when commodity prices recover.

2011 Performance Highlights

Highlights of Exelon's strong 2011 operating and financial performance and achievements in policy advocacy, participating in industry consolidation, organic growth and protecting shareholder and bondholder value through active risk management included the following:

- Operating earnings of $4.16 per share exceeded budget, and balance sheet and credit metrics remained strong.
- Operational strength was among the best in the industry. The nuclear fleet turned in a capacity factor greater than 93% for the ninth consecutive year. ComEd outage frequency metrics were better than planned and its best on record, with outage duration metrics on target despite exceptional summer storms. PECO's storm response was excellent, especially compared to its regional peers.
- Multiple regulatory and political challenges were addressed. Illinois legislation enacted in 2011 supports infrastructure investment, reduces regulatory lag, and provides reasonable returns on ComEd's equity for years to come. The U.S. EPA finalized two sets of regulations that met Exelon's expectations.

- Exelon Generation added 138 MW of nuclear capacity in 2011, bringing the uprate program total to 240 MW. Exelon Generation also acquired Wolf Hollow, a 720 MW gas plant in north Texas and the Antelope Valley Solar Ranch, a 230 MW solar development in California.
- Exelon accomplished approximately 81% of the Exelon 2020 goal to reduce, offset, or displace 15.7 million metric tons of CO2 emissions per year by 2020, ahead of schedule.
- The Constellation merger is on track with merger close anticipated in the first quarter of 2012, absent any delay in the FERC approval process, giving Exelon national scope and greater scale.

Pay for Performance

Exelon's executive compensation programs are designed to motivate and reward senior management to achieve Exelon's vision of being the best group of electric generation and electric and gas delivery companies in the United States, providing superior value for Exelon's customers, employees, investors and the communities Exelon serves. The compensation committee has adopted a pay−for−performance philosophy, which places an emphasis on pay−at−risk. Exelon's compensation program is designed to reward superior performance, that is, meeting or exceeding financial and operational goals set by the compensation committee. When excellent performance is achieved, pay will increase. Failure to achieve the target goals established by the compensation committee will result in lower pay.

Reductions in Compensation for 2010

After a difficult year for earnings in 2009, and in anticipation of continued earnings challenges in 2010, the compensation committee and the Exelon and ComEd boards of directors took the following actions at the beginning of 2010 to reduce compensation:

- Executive salaries were frozen, except for changes in responsibilities;
- The annual incentive program ("AIP") payout scale was recalibrated to reduce the threshold payout from 50% to 25% and to reduce the payout at plan from 100% to 50%, while leaving distinguished payout at 200%;
- The shareholder protection features in the annual incentive plan were enhanced by limiting key performance indicator payouts to no more than ten percentage points above the earnings payout percentage;
- The target values for long−term incentives were reduced by approximately 33%; and
- The company fixed match on 401(k) contributions was reduced from 5% to 3% of base salary, with the potential for a formula−based profit sharing contribution of up to an additional 3% of base salary.

Changes to Incentive Compensation Programs for 2011

In January 2011 the compensation committee considered performance under the 2010 performance share award plan. Because of the lagging total shareholder return, which was the goal for the 2010 performance share program, the committee determined that no performance shares would be paid out.

In January 2011 the compensation committee also established the incentive compensation programs for 2011, including changes from the 2010 design. The committee recognized that the company's long−term prospects would be harmed if it continued 2010's compensation reductions for another year, and that it was necessary to reward strong performance that would contribute to future growth even if total shareholder returns continued to lag due to factors outside of management's control.

The 2011 AIP was structured substantially similar to the 2010 AIP, except that the payout scale was restored to pay 50% at threshold and 100% at plan, and the shareholder protection feature was changed to limit key performance indicator payouts to no more than 20 percentage points above the earnings payout percentage. The 2011ComEd AIP was substantially similar to the 2010 ComEd AIP, except that the net income limiter was restructured to limit key performance indicator payouts to no more than 20 percentage points above the operating net income performance.

The long−term incentive program was also changed in 2011. The compensation committee was concerned about the volatility in the payouts (which ranged from 200% for the 2006−2008 performance period to 0% for the 2008−2010 performance period). The compensation committee believed it would be prudent to restructure the long−term incentive program to reward the achievement of operational and financial performance with respect to factors critical to the Company's long−term success and that are largely within management's control. Accordingly, both the goals and the mix of long−term incentives were changed. Senior vice presidents and higher officers will continue to receive awards of stock options, reflecting their ability to make decisions with the potential for long term increases in shareholder value. Such officers will continue to receive 25% of their targeted long−term incentive opportunity in the form of stock options and 75% in the form of performance shares. Vice presidents will have their targeted long−term incentive opportunity reallocated to come 50% from performance shares and 50% from time−vested restricted stock. In connection with the realignment of goals, the compensation committee determined that it would be advisable to narrow the payout opportunity by reducing the maximum payout from 200% of target to 125% of target, while raising the payout at threshold from 50% to 75%. The compensation committee may also approve individual performance multipliers ("IPMs") of 50% to 110% of target (up to 120% of target for vice presidents) which can result in a maximum payout of 137.5% (110% of 125%) for senior vice presidents and higher officers.

The specific goals for the performance share award program for 2011 were changed from the exclusive reliance on comparative total shareholder return measures previously used to a qualitative assessment by the compensation committee of performance against six goals reflecting actions and initiatives enhancing the long−term value of the company. These goals include the following:

- Operational excellence, delivering low cost, clean and reliable energy and operating our facilities safely;
- Financial management, executing cost discipline and optimizing the balance sheet, cash flow, liquidity, and liability management to deliver value return;
- Policy advocacy, engaging with stakeholders to shape public policy to benefit shareholders and consumers;
- Participating in industry consolidation only when the time and price are right;
- Organic growth, creating commercial opportunities that leverage Exelon's unique investment platform, such as the nuclear uprate program; and
- Protecting shareholder and bondholder value through active risk management.

Total shareholder return data continues to be provided to the compensation committee to be taken into account in making the final payout decision. The total shareholder return data compares Exelon to a group of nine utilities with more than 25% unregulated generation.

The compensation committee also approved two changes to the terms of performance shares. First, the committee added a restriction on the sale by a senior vice president or higher officer of any performance shares from a grant until all of the shares from the grant have vested, three years after the grant date. Second, all awards will be settled in shares. These changes were intended to further align the interests of recipients with shareholders by increasing the amount of incentive compensation paid in stock and by requiring senior officers to hold the stock for a longer period of time.

Table of Contents

The ComEd 2011 long term incentive program is substantially similar to the 2010 program.

Effect of Financial Performance on Incentive Compensation

Exelon's AIP is based to a significant extent on adjusted (non−GAAP) operating earnings per share. Exelon's original guidance for 2011 for adjusted (non−GAAP) operating earnings was a range of $3.90 to $4.20, and the target, for a 100% payout, was $4.05. During the year, the guidance range was raised on July 27, 2011 to $4.05 to $4.25 per share, and raised again on November 4, 2011 to $4.15 to $4.30 per share. Actual adjusted (non−GAAP) operating earnings as reported in Exelon's earnings release on January 25, 2012 were $4.16, or 131.43% of target. However, because earnings were below distinguished, the shareholder protection features in the annual incentive plan took effect and limited some of the AIP payouts on Exelon Generation operating company/business unit key performance indicator goals.

As discussed above, Exelon's performance share award program is based on achieving goals reflecting actions and initiatives enhancing the long−term value of the company.

The following table shows the correlation between levels of financial performance and incentive compensation in 2011:

Year	Adjusted (non−GAAP) Earnings Per Share	% of Target For Earnings Goals in Annual Incentive Plan (AIP)	Limit on % of Payout for Other Goals in AIP based on Earnings	Performance Share Unit Payout as % of Target
2011	$ 4.16	131.43%	151.43%	115.00%

For additional information about Exelon's financial results for 2010 and 2011, see Item 7—Management's Discussion and Analysis of Financial Condition and Results of Operations.

Value of Realized Compensation for Named Executive Officers

In determining the alignment of pay and performance, it is more important to consider the amount of compensation actually realized than the amount of potential compensation that is the basis for the use of grant date fair values as mandated by the SEC. No value from stock options can be realized to the extent that the strike price is higher than the current price of Exelon's stock. None of the stock options granted since January 2006 is in the money; the 2006 strike price was $58.55; 2007, $59.96; 2008, $73.29; 2009, $56.51; 2010, $46.09; and 2011, $43.40, while the price of Exelon's common stock on January 23, 2012 was $39.83. The Summary Compensation Table, however, reports the potential value of stocks options at their grant date fair value. Similarly, no value was realized from performance shares in 2010 when no performance shares were awarded, even though the Summary Compensation Table shows the potential value of the performance shares at their grant date fair value.

The following table presents the compensation actually realized by Exelon's named executive officers (NEOs). Values for non−equity compensation are the same as in the Summary Compensation Table. Equity compensation is valued using the actual number of performance shares awarded at the end of the performance period multiplied by the stock price on the award date and no value for stock options that are not in the money, instead of grant date fair values.

For most NEOs, the compensation they actually received in 2011 was higher than in 2010 or 2009. This chiefly reflects the payout of performance shares and the ComEd long term incentive program at 115% of target in 2011, after a zero payout in 2010.

Compensation Actually Paid to NEOs
(Equity Valued at Actual Value on Award Date Instead of Grant Date Fair Value)

Name and Principal Position (A)	Year (B)	Salary ($) (C)	Bonus ($) (D)	Stock Awards Valued at Award Date ($) (E)	Value of In the Money Stock Options at 1/23/2012 ($) (F)	Non−Equity Incentive Plan Compensation ($) (G)	Change in Pension Value and Nonqualified Deferred Compen− sation Earnings ($) (H)	All Other Compen− sation ($) (I)	Total ($) (J)
Rowe	2011	$1,512,904	$ —	$4,736,185	$ —	$ 2,500,000	$1,505,192	$470,008	$10,724,289
	2010	1,475,000	—	—	—	2,474,313	2,878,315	405,521	7,233,149
	2009	1,468,077	—	2,717,743	—	1,573,825	173,566	416,947	6,350,158
O'Brien	2011	555,292	—	824,481	—	575,172	145,395	44,344	2,144,684
	2010	536,000	63,177	—	—	631,768	213,789	28,712	1,473,446
	2009	532,923	—	538,101	—	395,970	233,772	55,464	1,756,230
Hilzinger	2011	472,954	—	430,562	—	402,060	80,484	37,035	1,423,095
	2010	446,000	18,962	—	—	379,245	88,452	20,465	953,124
	2009	442,769	13,079	261,238	—	261,579	85,891	31,725	1,096,281
Barnett	2011	317,617	7,500	251,925	—	216,709	50,030	21,490	865,271
	2010	309,900	12,435	—	—	248,695	59,205	11,876	642,111
	2009	307,996	—	163,758	—	153,788	55,038	23,407	703,987
Pacilio	2011	613,000	35,799	2,936,485	—	715,982	1,132,392	37,566	5,471,224
	2010	450,946	—	451,800	—	385,316	998,116	23,211	2,309,389
Crane	2011	858,692	—	1,557,353	—	1,136,857	1,430,802	75,513	5,059,217
	2010	825,000	—	—	—	1,132,313	1,621,679	87,155	3,666,147
	2009	821,154	—	882,024	—	680,213	719,399	76,140	3,178,930
Von Hoene	2011	621,058	—	1,145,113	—	616,071	110,241	77,761	2,570,244
	2010	600,000	—	—	—	686,250	123,906	35,190	1,445,346
Pardee	2011	653,527	—	947,197	—	704,889	558,698	44,452	2,908,763
	2010	588,585	—	301,200	—	485,705	449,842	23,651	1,848,983
	2009	568,615	16,903	440,620	—	338,052	221,082	33,192	1,618,464
Adams	2011	351,449	—	343,534	—	289,759	101,441	7,646	1,093,829
	2010	332,800	29,378	—	—	293,779	160,420	8,531	824,908
	2009	330,339	16,515	206,668	—	165,152	190,121	4,100	912,895
Bonney	2011	318,299	16,217	285,454	—	174,344	308,568	17,549	1,120,431
	2010	306,000	19,645	—	—	196,452	206,962	10,049	739,108
	2009	284,586	—	144,262	—	121,482	337,150	14,840	902,320
Acevedo	2011	223,813	—	150,569	—	102,232	30,466	13,895	520,975
	2010	216,000	—	—	—	107,141	34,247	7,082	364,470
	2009	212,208	3,695	84,385	—	73,899	33,958	10,610	418,755

Compensation Actually Paid to NEOs
(Equity Valued at Actual Value on Award Date Instead of Grant Date Fair Value)

Name and Principal Position (A)	Year (B)	Salary ($) (C)	Bonus ($) (D)	Stock Awards Valued at Award Date ($) (E)	Value of In the Money Stock Options at 1/23/2012 ($) (F)	Non−Equity Incentive Plan Compensation ($) (G)	Change in Pension Value and Nonqualified Deferred Compen−sation Earnings ($) (H)	All Other Compen−sation ($) (I)	Total ($) (J)
Clark	2011	$586,373	$ —	$ —	$ —	$ 1,681,714	$ 282,606	$ 52,949	$2,603,642
	2010	567,000	39,016	—	—	437,519	928,222	32,315	2,004,072
	2009	564,385	—	254,300	—	1,461,250	180,950	85,888	2,546,773
Trpik	2011	296,846	75,000	—	—	513,260	45,363	25,278	955,747
	2010	280,000	18,620	—	—	129,635	49,626	15,644	493,525
	2009	263,810	6,300	43,417	—	257,556	51,563	27,312	649,958
Pramaggiore	2011	444,481	—	—	—	1,079,481	79,202	24,464	1,627,628
	2010	415,000	54,978	—	—	277,533	86,673	17,158	851,342
	2009	391,269	24,900	—	—	776,342	89,876	33,774	1,316,161
Donnelly	2011	359,265	75,000	—	—	724,381	81,290	32,319	1,272,255
	2010	350,000	28,448	—	—	198,054	114,239	20,934	711,675
	2009	326,154	9,625	—	—	574,610	134,917	35,392	1,080,698
O’Neill	2011	338,423	100,000	—	—	559,865	53,259	28,719	1,080,266
	2010	315,000	24,384	—	—	169,760	57,974	14,734	581,852

Elimination of Future Excise Tax Gross−ups on Termination Payments and Certain Perquisites

The compensation committee has acted to reduce severance payments and certain perquisites. In April 2009, the compensation committee adopted a policy that future employment or severance agreements that provide for benefits for NEOs on account of termination will not include an excise tax gross−up. The policy is more fully described below under Other Benefits—*Change In Control and Severance Benefits.* On October 27, 2009, the board of directors approved the Third Amended and Restated Employment Agreement with Mr. Rowe. In the agreement, Mr. Rowe’s previous excise tax gross−up benefit was eliminated consistent with the policy. The agreement is more fully described below under Potential Payments upon Termination or Change in Control—Employment Agreement with Mr. Rowe. Anticipating an emerging trend among the peer group to curtail perquisite programs in the future, on January 22, 2007, the compensation committee approved the phase−out of many executive perquisites, effective January 1, 2008. The eliminated perquisites included: leased vehicles (existing leases allowed to expire), financial and estate planning, tax preparation and health and dining/airline club memberships.

Recoupment Policy

As described more fully below, in May 2007, the board of directors adopted a recoupment policy as part of Exelon’s corporate governance principles that provides that the board may in its discretion seek recoupment of incentive compensation from an executive officer in the event of fraud or intentional misconduct resulting in a restatement of financial results and the payment of more incentive compensation than would have been earned.

Sales Restrictions for Performance Shares; Stock Ownership and Trading Requirements

As noted above, in 2011 the compensation committee amended the terms of performance shares granted beginning in 2011 to provide that senior vice presidents and above may not sell any performance shares from a grant until all of the shares from the grant have vested, three years after the grant date. Officers of Exelon and its subsidiaries (other than ComEd) are required to own certain amounts of Exelon stock. As of January 31, 2011, each of the named executive officers owned at least 162% of their target, and Mr. Rowe owned 389% of his target. Executive vice presidents and higher officers may only sell Exelon stock through a Rule 10b5−1 stock trading plan. The use of stock trading plans permits diversification as a part of retirement and tax planning activities while reducing the risk that investors will view such sales as a signal of negative expectations for Exelon's future stock value. All of these provisions are designed to strengthen the alignment of executives' interests with shareholders. Additional information is below in the Stock Ownership Guidelines section in Item 12—Security Ownership of Certain Beneficial Owners and Management and related Stockholder Matters.

Shareholder Advisory Vote on Executive Compensation

At Exelon's 2011 annual meeting of shareholders, over 95% of the shares voted were in favor of the compensation of Exelon's named executive officers as disclosed in the proxy statement for the 2011 annual meeting of shareholders, including the Compensation Discussion and Analysis, the 2010 Summary Compensation Table and other related tables and disclosures. The compensation committee believes that the vote confirms its view that Exelon's compensation programs are performance−based and consistent with sound executive compensation policy, and the committee will consider the outcome of the shareholder advisory vote on executive compensation each year as it makes future compensation decisions.

In addition, over 77% of the shares voted were in favor of holding the advisory vote on executive compensation on an annual basis, as was recommended by the board of directors. The board subsequently determined that it would follow the shareholders' recommendation and hold the advisory vote on executive compensation at each annual meeting.

Objectives of the Compensation Program

The compensation committee has designed Exelon's executive compensation program to motivate and reward senior management for achieving financial, operational and strategic success consistent with Exelon's vision of being the best group of electric generation and electric and gas delivery companies in the United States, providing superior value for Exelon's customers, employees, investors and the communities Exelon serves. The compensation programs are also designed to attract and retain outstanding executives. Exelon's compensation program has three principles, as described below:

1. A substantial portion of compensation should be performance−based.

The compensation committee has adopted a pay−for−performance philosophy, which places an emphasis on pay−at−risk. Exelon's compensation program is designed to reward superior performance, that is, meeting or exceeding financial and operational goals set by the compensation committee. When excellent performance is achieved, pay will increase. Failure to achieve the target goals established by the compensation committee will result in lower pay. There are pay−for−performance features in both cash and equity−based compensation. The NEOs listed in the Summary Compensation Table participate in an annual incentive plan that provides cash compensation based on the achievement of performance goals established each year by the compensation committee. A substantial portion of each NEO's equity−based compensation is in the form of performance share units that are paid to the extent that longer−range performance goals set by the compensation committee are met, with the balance delivered in stock options that have value only to the extent that Exelon's stock price increases following the option grant date. As a result of the performance−based features of his cash and equity−based compensation, 83% of Mr. Rowe's 2011 target total direct compensation (base salary plus annual and long−term incentive compensation) was at−risk. Similarly, of the other NEOs' 2011 target total direct compensation, approximately 50% to 77% was at−risk.

2. A substantial portion of compensation should be granted as equity−based awards.

The compensation committee believes that a substantial portion of compensation should be in the form of equity−based awards in order to align the interests of the NEOs with Exelon's shareholders. The objective is to make the NEOs think and act like owners. Equity−based compensation is in the form of performance share units, stock options, and restricted stock units that are valued in relation to Exelon's common stock, and they gain value in relation to the market price of Exelon's stock. Conversely, when the market price of Exelon's stock decreases, the value of the equity compensation decreases.

3. Exelon's compensation program should enable the company to compete for and retain outstanding executive talent by benchmarking compensation against an appropriate peer group.

Exelon's shareholders are best served when we can successfully recruit and retain talented executives with compensation that is competitive and fair. The compensation committee strives to deliver total direct compensation generally at the median (the 50th percentile), which is deemed to be the competitive level of pay of executives in comparable positions at peer companies with which we compete for executive talent. If Exelon's performance is at target, the compensation will be targeted at the 50th percentile; if Exelon's performance is above target, the compensation will be targeted above the 50th percentile, and if performance is below target, the compensation will be targeted below the 50th percentile. This concept reinforces the pay−for−performance philosophy.

Each year the compensation committee commissions its consultant to prepare a study to benchmark total direct compensation against a peer group of companies. The study includes an assessment of competitive compensation levels at high−performing energy services companies and other large, capital asset−intensive companies in general industry, since the company competes for executive talent with companies in both groups. All competitive data was aged to January 2011 using a 3% annual update factor. The study indicated that base salaries increased about 3% on average, with some positions up or down slightly, target annual incentives were similar to the prior year's and target long−term incentives were up slightly on a year− over−year basis. The consultant recommended that in 2011 Exelon should return to its pre−2010 compensation approach for base salary and annual incentives, including normal merit increases for base salary averaging around 3% and restoring the annual incentive program scale to a 100% payout for planned target performance. He also recommended changing the long−term incentive mix and design as discussed above. The consultant considered the changes to Exelon's management structure in 2010 to determine how Exelon's positions compared with positions at its peers by establishing a benchmark match for each Exelon executive in the competitive market, where available, and data for positions matched to business−unit level jobs were size adjusted using regression analysis, where available. The study reviewed each element of compensation as well as total direct compensation.

The peer group criteria include three primary factors:

- having revenue similar to Exelon's $18.6 billion,
- having market capitalization generally greater than $5 billion, and
- a balance of industry segments.

Table of Contents

The members of the peer group are reviewed each year to determine whether their inclusion continues to be appropriate. Generally the peer group is comprised of 24 companies: 12 general industry companies and 12 energy services companies. The companies were selected by the compensation committee from the Towers Perrin Energy Services Industry Executive Compensation Database and their Executive Compensation Database. The peer group was the same in 2011 as it was in 2010. The peer group includes the following companies:

General Industry Companies	FY 2010 Revenue ($ Million)	FY 2010 Total Assets ($ Million)	November 2011 Market Cap ($ Million)
3M Co.	$ 26,662	$ 30,156	$ 56,796
Abbott Laboratories	35,167	59,462	84,978
Caterpillar Inc.	42,588	64,020	63,291
General Mills, Inc.	14,880	18,675	25,706
Hess Corporation	33,950	35,396	20,164
Honeywell International Inc.	33,370	37,834	41,885
International Paper Co.	25,179	25,368	12,413
Johnson Controls Inc.	40,833	29,676	21,418
Pepsico, Inc.	57,838	68,153	100,058
PPG Industries Inc.	13,423	14,975	13,551
Union Pacific Corporation	16,965	43,088	49,955
Weyerhaeuser Co.	6,552	13,429	9,006
Energy Services Companies			
American Electric Power Co., Inc.	$ 14,427	$ 50,455	$ 19,162
CenterPoint Energy, Inc.	8,785	20,111	8,476
Dominion Resources, Inc.	15,197	42,817	29,403
Duke Energy Corporation	13,972	59,090	27,787
Edison International	12,409	45,530	12,808
Entergy Corporation	11,488	38,685	12,392
FirstEnergy Corp.	12,911	34,805	18,598
NextEra Energy, Inc.	15,317	52,994	23,425
PG & E Corp.	13,841	46,025	15,764
Public Service Enterprise Group Inc.	11,793	29,909	16,665
Southern Company	17,456	55,032	37,847
Xcel Energy Inc.	10,311	27,388	12,749
Exelon Corporation	**$ 18,644**	**$ 52,240**	**$ 29,378**

The compensation committee generally applies the same policies with respect to the compensation of each of the individual NEOs. The compensation committee carefully considers the roles and responsibilities of each of the NEOs relative to the peer group, as well as the individual's performance and contribution to the performance of the business in establishing the compensation opportunity for each NEO. The differences in the amounts of compensation awarded to the NEOs reflect primarily two factors, the differences in the compensation paid to officers in comparable positions in the peer group and differences in the individual responsibility and experience of the Exelon officers. Time in position affects where individuals are relative to market percentiles, with cash compensation generally at the median and incentive compensation slightly above the median. The nuclear organization's pay is generally closer to the 75th percentile given the size and quality of Exelon's nuclear fleet. The delivery company presidents were evaluated as a blend of top energy delivery executives and freestanding CEOs, given the amount of independence they have. Mr. Rowe's target compensation was based on the same factors as the other NEOs, but his compensation reflected a greater degree of policy and decision−making authority and a higher level of responsibility with respect to strategic direction and financial and operating results of Exelon. His target compensation was assessed relative to other CEOs in the peer group. Mr. Rowe's compensation also reflects the fact that Exelon has the largest nuclear fleet in the industry and one of the largest market capitalizations. It also reflects that Mr. Rowe is the senior CEO in the industry.

The role of individual performance in setting compensation

While the consideration of benchmarking data to assure that Exelon's compensation is competitive is a critical component of compensation decisions, individual performance is factored into the setting of compensation in three ways:

- First, base salary adjustments are based on an assessment of the individual's performance in the preceding year as well as a comparison with market data for comparable positions in the peer group.
- Second, annual incentive targets are based on the individual's role in the enterprise—the most senior officers with responsibilities that span specific business units or functions have a target based on earnings per share for the company as a whole, while individuals with specific functional or business unit responsibilities have a significant portion of their targets based on the performance of that functional or business unit.
- Third, consideration is given as to whether an individual performance multiplier would be appropriately applied to the individual's annual incentive plan or performance share program award, based on the individual's performance. The individual performance multiplier can result in a decision not to make an award or to decrease the amount of the award or to increase the amount of the award by up to 10% (20% for vice presidents). For the annual incentive plan, the adjusted award cannot exceed the maximum amount that could be paid to the executive based on achievement of the objective performance criteria applicable under the plan. For the performance share award program, the individual performance multiplier can increase an individual award above the maximum for plan performance by up to 10% above the 125% maximum, or 137.5% (for vice presidents, up to 20% above the 125% maximum, or 150%)

Elements of Compensation

This section is an overview of our compensation program for NEOs. It describes the various elements and discusses matters relating to those items, including why the compensation committee chooses to include items in the compensation program. The next section describes how 2011 compensation was determined and awarded to the NEOs.

Exelon's executive compensation program is comprised of four elements: base salary; annual incentives; long−term incentives; and other benefits.

Cash compensation is comprised of base salary and annual incentives. Equity compensation is delivered through long−term incentives. Together, these elements are designed to balance short−term and longer−range business objectives and to align NEOs' financial rewards with shareholders' interests. For all NEOs other than those at ComEd, approximately 39% to 68% of NEOs' total target direct compensation is delivered in the form of cash and equity compensation accounts for approximately 32% to 61% of NEO total target direct compensation. For ComEd NEOs, all total target direct compensation is delivered in the form of cash and there is no equity component, consistent with continuing efforts to recognize ComEd's independence and to maximize recovery in rates. The range in the mix of cash and equity compensation is consistent with competitive compensation practices among companies in the peer group. The compensation committee believes that this mix of cash and equity compensation strikes the right balance of incentives to pursue specific short and long−term performance goals that drive shareholder value.

Table of Contents

Base Salary

Exelon's compensation program for NEOs is designed so that approximately 17% to 50% of NEO total direct compensation is in the form of base salary, consistent with practices at the companies in the peer group.

Annual Incentives

Annual incentive compensation is designed to provide incentives for achieving short−term financial and operational goals for the company as a whole, and for subsidiaries, individual business units and operating groups, as appropriate. Under the annual incentive program, cash awards are made to NEOs and other employees if, and only to the extent that, performance conditions set by the compensation committee are met.

Long−term Incentives

Long−term incentives are made available to executives and key management employees who affect the long−term success of the company. The long−term incentive compensation programs are primarily equity based and designed to provide incentives and rewards closely related to the interests of Exelon's shareholders, generally as measured by the achievement of strategic goals under the terms of the performance share program and stock price appreciation.

A portion of the long−term incentive compensation for all officers (other than officers of ComEd) is in the form of performance share units that are awarded only to the extent that performance conditions established by the compensation committee are met. The balance of long−term incentive compensation is in the form of time−vested stock options that provide value only if, and to the extent that, the market price of Exelon's common stock increases following the grant, and time−vested restricted stock. Stock options are only awarded to officers, senior vice president and above, because they are in a position to make decisions with the potential for long term increases in shareholder value. For vice presidents, the balance of long−term incentive compensation is in the form of time−vested restricted stock. The use of these forms of long−term incentives is consistent with the practices in our peer group. The mix of long−term incentives is determined by the compensation committee. As part of its decision making process the compensation committee reviews competitive compensation practices of companies in the peer group.

Stock option repricing is prohibited by policy or the terms of the company's long−term incentive plans. Accordingly, no options have been repriced. Stock option awards are generally granted annually at the regularly scheduled January compensation committee meeting when the committee reviews results for the preceding year and establishes the compensation program for the coming year. There were no off−cycle grants of stock options made in 2011.

In 2007, consistent with the continuing efforts to recognize ComEd's independence, the compensation committee recommended, and the ComEd board adopted, a separate long−term incentive program for ComEd's executives. The goals under the ComEd long−term incentive program are the achievement of goals relating to total cost, outage duration and frequency and safety, operational performance, employee engagement and communication, and environmental commitments. Payments under this plan are made in cash, and are awarded annually by the ComEd board based on the assessment of performance during the year and the recommendation of the Exelon compensation committee. Because compensation above target is not recoverable in rates, any payout above 100% will be consistent with Exelon long−term incentive compensation levels. In addition, payouts may be modified at the discretion of the ComEd Chairman and CEO and the board of directors based on overall performance of the company and the prevailing economic environment at the time of the award. Other features of the program include the payout of awards ranging from 0−200% of target and vesting over three years.

Executive stock ownership and trading requirements

To strengthen the alignment of executives' interests with those of shareholders, officers of the company are required to own certain amounts of Exelon common stock by the later of five years after their employment or promotion to their current position. However, in 2007, the compensation committee terminated the stock ownership requirements for ComEd officers in light of the continuing efforts to recognize ComEd's independence and the compensation committee's recommendation that ComEd officers participate in a separate cash−based long−term incentive program instead of receiving Exelon performance shares. For additional information about Exelon's stock ownership guidelines, please see the Stock Ownership Guidelines section in Item 12—Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters. For information about the restrictions on selling under the performance share award program, see above under Pay for Performance—*Changes to Incentive Compensation Programs for 2011.*

Exelon has adopted a policy requiring officers, executive vice presidents and above, who wish to sell Exelon common stock to do so only through Rule 10b5−1 stock trading plans, and permitting other officers to enter into such plans. This requirement is designed to enable officers to diversify a portion of their holdings in excess of the applicable stock ownership requirements in an orderly manner as part of their retirement and tax planning activities. The use of Section 10b5−1 stock trading plans serves to reduce the risk that investors will view routine portfolio diversification stock sales by executive officers as a signal of negative expectations with respect to the future value of Exelon's stock. In addition, the use of Rule 10b5−1 stock trading plans reduces the potential for accusations of trading on the basis of material, non−public information that could damage the reputation of the company. Exelon's stock trading policy does not permit short sales or hedging.

Other Benefits

Other benefits offered by Exelon include such things as qualified and non−qualified deferred compensation programs, post−termination compensation, retirement benefit plans and perquisites. The company also provides other benefits such as medical and dental coverage and life insurance to each NEO to generally the same extent as such benefits are provided to other Exelon employees, except that executives pay a higher percentage of their total medical premium. These benefits are intended to make our executives more efficient and effective and provide for their health, well−being and retirement planning needs. The compensation committee reviews these other benefits to confirm that they are reasonable and competitive in light of the overall goal of designing the compensation program to attract and retain talent while maximizing the interests of our shareholders.

Change In Control and Severance Benefits

The compensation committee believes that change in control employment agreements and severance benefits are an important part of Exelon's compensation structure for NEOs. The compensation committee believes that these agreements will help to secure the continued employment and dedication of the NEOs to continue to work in the best interests of shareholders, notwithstanding any concern they might have regarding their own continued employment prior to or following a change in control. The compensation committee also believes that these agreements and the Exelon Corporation Senior Management Severance Plan are important as recruitment and retention devices, as all or nearly all of the companies with which Exelon competes for executive talent have similar protections in place for their senior leadership.

In 2007, the compensation committee adopted a policy limiting the amount of future severance benefits to be paid to NEOs under future arrangements without shareholder approval to 2.99 times salary plus annual incentive. This policy clarifies that severance benefits include cash severance payments and other post−employment benefits and perquisites, but do not include:

- Amounts earned in the ordinary course of employment rather than upon termination, such as pension benefits and retiree medical benefits;
- Amounts payable under plans approved by shareholders;
- Amounts available to one or more classes of employees other than the NEOs;
- Excise tax gross−up payments, but only if the compensation includable in determining whether excise taxes apply exceed 110% of the threshold amount; otherwise the NEO's benefits are reduced so that no excise tax is imposed; and
- Amounts that may be required by existing agreements that have not been materially modified, Exelon's indemnification obligations or the reasonable terms of a settlement agreement.

In April 2008, the compensation committee determined that non−change in control severance benefits for senior vice presidents would be reset at 1.5 times annual salary and bonus, provided that those senior vice presidents with such benefits at 2 times annual salary and bonus would be grandfathered at that level.

In April 2009, the compensation committee adopted a policy that no future employment or severance agreement that provides for benefits for NEOs on account of termination will include an excise tax gross−up. The policy applies to employment, change in control, severance and separation agreements entered into, adopted, or materially changed on or after April 2, 2009, other than agreements changed to comply with law or to reduce or eliminate rights, agreements assumed in a corporate transaction, and automatic extensions or renewals where other terms are not changed. The compensation committee has the sole and absolute power to interpret and apply the policy, and it can amend, waive or terminate it if in the best interest of the company, provided that prompt disclosure is made.

Retirement Benefit Plans

The compensation committee believes that retirement benefit plans are an important part of the NEO compensation program. These plans serve a critically important role in the retention of senior executives, as retirement benefits increase for each year that these executives remain employed. The plans thereby encourage our most senior executives to remain employed and continue their work on behalf of the shareholders. Exelon sponsors both qualified traditional defined benefit and cash balance defined benefit pension plans and related non−qualified supplemental pension plans (the SERPs).

Exelon previously granted additional years of credited service under the SERP to a few executives in order to recruit or retain them. As of January 1, 2004, Exelon ceased the practice of granting additional years of credited service to executives under the non−qualified pension plans that supplement the Exelon Corporation Retirement Program for any period in which services are not actually performed, except that up to two years of service credits may be provided under severance or change in control agreements first entered into after such date. Service credits available under employment, change in control or severance agreements or arrangements (or any successor arrangements) in effect as of January 1, 2004 were not affected by this policy. To attract a new executive, Exelon is permitted to grant additional years of service under the SERP related to its cash balance pension plan to make the executive whole for retirement benefits lost from another employer by joining Exelon, provided such a grant is disclosed to shareholders. To date, Exelon has not made any such grant.

Perquisites

The compensation committee eliminated most perquisites effective January 1, 2008. Exelon provides limited perquisites intended to serve specific business needs for the benefit of Exelon; however, it is understood that some may be used for personal reasons as well. When perquisites are utilized for personal reasons, the cost or value is imputed to the officer as income and the officer is responsible for all applicable taxes; however, in certain cases, the personal benefit is closely associated with the business purpose in which case the company may reimburse the officer for the taxes due on the imputed income. For additional information about perquisites, see the All Other Compensation table and the related notes.

How The Amount of 2011 Compensation Was Determined

This section describes how 2011 compensation was determined and awarded to the NEOs.

The independent directors of the Exelon board, on the recommendations of the Exelon corporate governance committee, conducted a thorough review of Mr. Rowe's performance in 2011. The review considered performance requirements in the areas of operational excellence, finance management, policy advocacy, opportunistic mergers and acquisitions, organic growth, risk management, succession planning and organizational effectiveness, leadership, and board relations. Mr. Rowe prepared a detailed self−assessment reporting to the board on his performance during the year with respect to each of the performance requirements. The Exelon board considered the financial highlights of the year and a strategy scorecard that assessed performance against the company's vision and goals. The factors considered included:

- goals with respect to protecting the current value of the company, including:
  - delivering superior operating performance in terms of safety, reliability, efficiency, and the environment,
  - supporting competitive markets,
  - protecting the value of our generation assets, and
  - building healthy, self−sustaining delivery companies; as well as
- goals relating to growing long−term value, including:
  - organizational improvement,
  - advancing an environmental strategy that sets the industry standard for low carbon energy generation and delivery, and
  - rigorously evaluating new growth opportunities.

The Exelon board considered, in particular, the following results:

- Operational and financial performance that beat the plans set at the beginning of the year, despite low gas prices and the continued effect of the weak economy;
- The average capacity factor of the nuclear generating plants was high, with 2011 being the ninth consecutive year with capacity factor above 93%;
- ComEd and PECO turned in strong performance despite intense storm activity; both companies saw all−time peak demand this summer, despite the negative impacts of the economy on load;
- Operating earnings increased as compared to the prior year, and they were much better than was expected at the beginning of 2011 primarily due to incremental income tax benefits, strong

Table of Contents

sales and favorable pricing in Texas due to extreme summer heat, the effect of formula rate legislation in Illinois, partially offset by storm costs and incremental incentive compensation costs;

- ComEd's legislation that will support important infrastructure investment, reduce regulatory lag, and provide a reasonable return on investment for years to come, as well as favorable environmental regulations;
- 2011 progress in advancing longer−term goals, including:
  - progress on the multi−year nuclear uprate strategy, with 240 MW added to date,
  - the acquisition of Wolf Hollow, a 720 MW gas plant in north Texas, the Antelope Valley Solar Ranch, a 230 MW solar development project in California, and Exelon Wind's addition of 90 MW of wind capacity in Michigan), all with long−term power purchase agreements in place, ensuring continued stable value; and
- Progress in talent development, diversity, succession planning, and the corporate culture.

How base salary was determined

At its January 24, 2011 meeting, the compensation committee reviewed base salary data for the NEOs listed in the Summary Compensation Table as compared to the compensation data for the 50^{th} and 75^{th} percentile of the peer group, and the compensation consultant's recommendation of a budget for base salary increases averaging 3%. Based on this review and their individual performance reviews, including the review of Mr. Rowe's performance by the corporate governance committee and the independent directors, the NEOs received base salary increases effective as of March 1, 2011 that averaged between 3% and 5%, although most of the NEOs received somewhat higher base salary increases than the 3% budget to meet the market for their positions. These increases were made after base salaries had been frozen in 2010 except for NEOs that had received promotions.

In May 2011 Messrs. Pacilio and Pardee received increases in their base salaries and incentive compensation targets in order to retain them in light of an offer by a competitor to hire Mr. Pacilio and the expectation that competitors would also try to hire Mr. Pardee. The committee determined that given the high degree of centralization in the nuclear organization, it was imperative that Exelon have the very best nuclear executives and that it needs to pay them commensurately.

The amounts of base pay, percentages of increase, and effective dates of base salary increases are set forth in the following table.

Exelon, Generation and PECO

Name	Base Salary	Percent Increase	Effective Date
Rowe	$1,520,000	3.1%	3/1/2011
O'Brien	560,000	4.5	3/1/2011
Hilzinger	478,000	7.2	3/1/2011
Barnett	319,500	3.1	3/1/2011
Pacilio	495,000	4.2	3/1/2011
Pacilio	675,000	36.4	5/2/2011
Crane	865,000	4.8	3/1/2011
Von Hoene	625,000	4.2	3/1/2011
Pardee	618,000	3.0	3/1/2011
Pardee	675,000	9.2	5/2/2011
Adams	356,000	7.0	3/1/2011
Bonney	321,300	5.0	3/1/2011
Acevedo	225,720	4.5	3/1/2011

Name	Base Salary	Percent Increase	Effective Date
Clark	$ 590,000	4.1%	3/1/2011
Trpik	300,000	7.1	3/1/2011
Pramaggiore	450,000	8.4	3/1/2011
Donnelly	361,000	3.1	3/1/2011
O'Neill	340,000	3.0	3/1/2011

How 2011 annual incentives were determined

For 2011, the annual incentive payments to Mr. Rowe and each of nine other senior executives were funded by a notional incentive pool established by the Exelon compensation committee under the Annual Incentive Plan for Senior Executives, a shareholder−approved plan, which is intended to comply with Section 162(m) of the Internal Revenue Code. The incentive pool was funded with 1.5% of Exelon's 2011 operating income, the same percentage used in 2010 and 2009, but was not fully distributed to participants because the committee decided on substantially lesser awards.

Annual incentive payments for 2011 to Messrs. Rowe, O'Brien, Crane, Clark, Pacilio, Pardee, Von Hoene, and Hilzinger and Ms. Pramaggiore were made from the portion of the incentive pool available to fund awards for each of them based on the company's operating earnings per share, adjusted for non−operating charges and other unusual or non−recurring items.

For 2011, the annual incentive payout scale was recalibrated so that the payout at threshold would be 50% of target rather than 25% of target, the payout at plan would be 100% of target rather than 50% of target, and the payout at distinguished would remain capped at 200%. For executives with general corporate responsibilities, the goal was adjusted (non−GAAP) operating earnings per share so that they would focus their efforts on overall corporate performance. The earnings per share goal ranges were set to be like the forecast earnings ranges. In accordance with the design of the annual incentive program, the compensation committee reviewed 2011 earnings and decided not to include the effects of significant one−time charges or credits that are not normally associated with ongoing operations and mark−to−market adjustments from economic hedging activities in adjusting earnings for purposes of making awards under the annual incentive plan. The adjusted earnings are consistent with the adjusted (non−GAAP) operating earnings that Exelon reports in its quarterly earnings releases. For 2011, the adjustments included:

- mark−to−market impacts of economic hedging activities,
- unrealized gains and losses on nuclear decommissioning trust fund investments,
- costs associated with the Constellation merger and the Antelope Valley Solar Ranch One acquisition,
- financial impacts associated with the retirement of fossil generating units,
- non−cash tax items,
- recovery of costs pursuant to ComEd's distribution rate case order,
- benefits related to the acquisition of the north Texas Wolf Hollow natural gas−fired plant, and
- the effect of updated studies of asset retirement obligations, including nuclear decommissioning.

Actual adjusted (non−GAAP) operating earnings per share as reported in Exelon's earnings release on January 25, 2012 were $4.16.

Table of Contents

2011 annual incentive payments for other NEOs with specific business unit responsibilities were based upon a combination of adjusted (non−GAAP) operating earnings per share (so that they would focus on overall corporate performance) and business unit financial and/or operating measures, depending on the nature of their responsibilities (so they would focus on the performance of their business unit). Under the terms of the plan, the business unit financial measures are adjusted from GAAP measures. For ComEd executive officers, adjusted (non−GAAP) operating earnings of Exelon were not a goal, consistent with the continuing efforts to recognize ComEd's independence as described above. ComEd's goals included other financial and operational goals. The following table summarizes the goals and weights applicable to the NEOs for 2011:

Exelon, Generation and PECO

Name	Adjusted Operating Earnings Per Share	Adjusted Generation Net Income	Exelon Nuclear Fleet−Wide Capacity Factor	Adjusted Nuclear, Power, & Power Team BU Funding KPIs	Adjusted PECO Net Income	Adjusted PECO Total Cost	PECO Reliability, Safety, Customer Satisfaction Measures, Focused Initiatives & Environ−mental Index	Adjusted BSC Total Cost
Rowe	100 %	— %	— %	— %	— %	— %	— %	— %
O'Brien	50	—	—	—	25	—	25	—
Hilzinger	75	—	—	—	—	—	—	25
Barnett	25	—	—	—	25	25	25	—
Pacilio	50	25	25	—	—	—	—	—
Crane	100	—	—	—	—	—	—	—
Von Hoene	100	—	—	—	—	—	—	—
Pardee	50	25	—	25	—	—	—	—
Adams	25	—	—	—	25	25	25	—
Bonney	25	—	—	—	25	25	25	—
Acevedo	75	—	—	—	—	—	—	25

Name	Adjusted ComEd Total Capital Expenditures	Adjusted ComEd Total O&M Expense	ComEd Reliability, Safety, Customer Satisfaction Measures, Focused Initiatives & Environ−mental Index
Clark	25%	25%	50%
Trpik	25	25	50
Pramaggiore	25	25	50
Donnelly	25	25	50
O'Neill	25	25	50

Table of Contents

The following table describes the performance scale and result for the 2011 goals:

Exelon, Generation, and PECO

2011 Goals	Threshold	Target	Distinguished	2011 Results	Payout as a Percentage of Target
Adjusted (non−GAAP) Operating Earnings Per Share (EPS)	$ 3.60	$ 4.05	$ 4.40	$ 4.16	131.4%
Adjusted Generation Net Income ($M)	$1,716.4	$1,928.5	$ 2,092.4	$ 1,992.9	139.3%
Exelon Nuclear Fleet−Wide Capacity Factor	90.5%	92.5%	93.7%	93.3%	166.7%
Adjusted Nuclear, Power, & Power Team BU Funding KPIs	*	*	*	*	154.8%
Adjusted PECO Net Income ($M)	$ 309.9	$ 348.2	$ 377.7	$ 383.9	200.0%
Adjusted PECO Total Cost ($M)	$ 891.9	$ 849.4	$ 764.5	$ 827.1	126.3%
PECO Reliability Measure—Customer Average Interruption Duration Index (CAIDI) (minutes per outage)	95	89	85	103	— %
PECO Reliability Measure—System Average Interruption Frequency Index (SAIFI) (outages per customer)	0.94	0.83	0.75	0.85	90.9%
PECO Reliability Measure—Reduction in Gas Facility Service Record Inaccuracy	50,000	55,000	60,000	56,686	133.7%
PECO Safety Measure—Occupational Safety and Health Administration (OSHA) Recordable Rate	1.54	0.97	0.77	0.97	100.0%
PECO Customer Satisfaction (weighted combined score of residential, small business and large business customers)	80.0	82.0	84.0	82	100.0%
Adjusted BSC Total Cost ($M)	$ 661.1	$ 629.6	$ 566.6	$ 614.9	123.3%

* Performance scale is a composite of multiple measures.

2011 Goals	Threshold	Target	Distinguished	2011 Results	Payout as a Percentage of Target
Adjusted ComEd Total Capital Expenditures ($M)	$ 884.3	$842.2	$ 758.0	$ 841.5	100.8%
Adjusted ComEd Total O&M Expense ($M)	$ 715.3	$681.2	$ 613.1	$ 694.3	80.8%
ComEd Reliability Measure—CAIDI (minutes per outage)	95	89	85	88	125.0%
ComEd Reliability Measure—SAIFI (outages per customer)	1.09	0.94	0.90	0.84	200.0%
ComEd Safety Measure—OSHA Recordable Rate	1.54	1.04	0.99	0.91	200.0%
ComEd Customer Satisfaction (weighted combined score of residential, small business and large business customers)	79.0	81.0	83.0	81.1	105.0%
ComEd Focused Initiatives & Environmental Index	90.0%	100.0%	110.0%	113.0%	200.0%

The 2011 annual incentive program included the following shareholder protection features (SPF):

- If threshold earnings per share are not achieved, then no payments will occur; and
- Operating company/business unit key performance indicator payments cannot exceed the earnings per share performance by more than 20 percentage points.

As a result of 2011 earnings for AIP purposes being at 131.43% of target, the operating company/business unit key performance indicators could not exceed 151.43% of target. The effect of these SPF reductions is shown in the table below.

The ComEd annual incentive program includes a limit of payments above plan based on ComEd's operating net income (the "NI Limiter"). Payments are limited to no more than 20% above ComEd's net income performance.

In making annual incentive awards, the compensation committee has the discretion to reduce or not pay awards even if the targets are met.

With respect to the NEOs in the table below, individual performance multipliers (IPM) other than 100% were approved and recommended by the compensation committee based upon assessments of NEO performance and input from the CEO. Under the terms of the Annual Incentive Program, the individual performance multiplier is used to adjust awards from minus 50% to plus 10% (20% for vice presidents) subject to the maximum 200% of target opportunity and the amounts available under the incentive pool. Increases in IPM shown below reflect exceptional performance.

Table of Contents

Based on the performance against the goals shown in the tables above, and taking into account the reductions resulting from the shareholder protection feature and adjustments discussed above, the compensation committee recommended and the Exelon or the ComEd board of directors, as the case may be (or in the case of Mr. Rowe, the independent directors) approved the following awards for the NEOs:

Exelon, Generation, and PECO	Payout as a % of Target (pre−SPF)	Payout $ (pre−SPF)	SPF Reduction $	Payout as a % of Target (post−SPF & pre−IPM)	Payout $ (post−SPF & pre−IPM)	IPM %	Payout $ (post−SPF & post−IPM)
Rowe (1)	131.4%	$2,500,000	$ —	131.4%	$2,500,000	100%	$2,500,000
O'Brien	136.9	575,172	—	136.9	575,172	100	575,172
Hilzinger	129.4	402,060	—	129.4	402,060	100	402,060
Barnett	135.7	216,709	—	135.7	216,709	100	216,709
Pacilio	142.2	719,908	(3,926)	141.4	715,982	105	751,781
Crane	131.4	1,136,857	—	131.4	1,136,857	100	1,136,857
Von Hoene	131.4	616,071	—	131.4	616,071	100	616,071
Pardee	139.2	704,889	—	139.2	704,889	100	704,889
Adams	135.7	289,759	—	135.7	289,759	100	289,759
Bonney	135.7	174,344	—	135.7	174,344	105	183,061
Acevedo	129.4	102,232	—	129.4	102,232	100	102,232

ComEd	Payout as a % of Target	IPM %	Payout $
Clark	133.2%	100%	$589,214
Trpik	133.2	100	179,760
Pramaggiore	133.2	100	389,481
Donnelly	133.2	100	264,381
O'Neill	133.2	100	226,365

(1) Mr. Rowe's payout at 131.4% of Target was $2,497,142, but the Committee rounded the amount up to $2,500,000.

How long−term incentives were determined

The compensation committee reviewed the amount of long−term compensation paid in the peer group for positions comparable to the positions held by the NEOs and the committee then applied a ratio of stock options to performance shares in order to determine the target long−term equity incentives for each NEO, using Binomial valuation for stock options and a 90 day weighted−average price for the preceding quarter to value performance shares. Stock option grants for 2011 were all at the targeted amounts. The actual amounts of performance shares awarded to the NEOs depended on the extent to which the performance measures were achieved.

Stock option awards

The company granted non−qualified stock options to the Exelon Corporation senior officers, including the NEOs, but excluding the ComEd NEOs, on January 24, 2011. The stock option grants for 2011 were all at the targeted amounts. These options were awarded at an exercise price of $43.40, which was the closing price on the January 24, 2011 grant date.

Exelon performance share unit awards

The goals for the 2011 Long−Term Performance Share Unit Award Program were changed from the exclusive reliance on comparative total shareholder return measures previously used to a qualitative assessment by the compensation committee of performance against six goals reflecting actions and initiatives enhancing the long−term value of the company. These goals and highlights of performance included the following:

- Operational excellence, delivering low cost, clean and reliable energy and operating our facilities safely:
  - Operational strength is among the best in the industry. The nuclear fleet turned in a capacity factor greater than 93% for the ninth consecutive year. ComEd outage frequency metrics were better than planned and its best on record, with outage duration metrics on target despite exceptional summer storms. PECO’s storm response was excellent, especially compared to its regional peers.
  - Exelon accomplished approximately 56% of the Exelon 2020 goal to reduce, offset, or displace 15.7 million metric tons of CO2 emissions per year by 2020 ahead of schedule.
- Financial management, executing cost discipline and optimizing the balance sheet, cash flow, liquidity, and liability management to deliver value return:
  - Operating earnings of $4.16 exceeded budget, and balance sheet and credit metrics remained strong.
- Policy advocacy, engaging with stakeholders to shape public policy to benefit shareholders and consumers:
  - Multiple regulatory and political challenges were addressed. Illinois legislation enacted in 2011 supports infrastructure investment, reduces regulatory lag, and provides reasonable returns on equity for years to come. The U.S. EPA finalized two sets of regulations that met Exelon’s expectations.
- Participating in industry consolidation only when the time and price are right:
  - The Constellation merger is on track with merger close expected in the first quarter of 2012, giving Exelon national scope and scale.
  - Generation also acquired Wolf Hollow, a 720 MW gas plant in north Texas and the Antelope Valley Solar Ranch, a 230 MW solar development in California.
- Organic growth, creating commercial opportunities that leverage Exelon’s unique investment platform, such as the nuclear uprate program:
  - Generation added 138 MW of nuclear capacity in 2011, bringing the uprate program total to 240 MW.
- Protecting shareholder and bondholder value through active risk management:
  - Exelon continues to hedge at a rate below its minimum hedge targets for 2011−2013 based on a neutral to bearish forecast for power prices and natural gas prices during this period.

Table of Contents

In deciding to award performance shares at 115% of target, the committee also considered the following performance metrics and milestones:

Goal	Performance Cycle Targets	Results
Operational Excellence: Delivering low cost, clean, and reliable energy to our customers. Investing in our nuclear plants and utilities, and safely operating them at world class levels.	OSHA Recordable Rate (safety) − Exelon	Meets
	Outage duration − ComEd, PECO	ComEd − Meets PECO − Below
	Outage frequency − ComEd, PECO	ComEd − Exceeds PECO − Meets
	Capacity Factor − Nuclear	Meets
	EFORd (Equivalent Forced Outage Rate − Demand) − Fossil Fleet	Meets
	Green House Gas (GHG) Commitment	Meets
	Delivery Synergies and Cooperation on Like Projects and Operations	Meets
Financial Management: Executing cost discipline, optimizing the balance sheet, cashflow, liquidity, meeting earnings targets, and liability management to deliver on our value return commitments.	Operating EPS	Meets
	Total O&M (Operating and Maintenance)	Below
	Total Capital Expenditures	Below
	Free Cash Flow (Full Year)	Meets
	ROE − ComEd, PECO	ComEd − Meets PECO − Meets
	Funds from Operations / Debt − ExGen, HoldCo	Meets
	Investment Returns: Actual vs Passive Benchmark − Pension	Exceeds
Policy Advocacy: Engaging with our external stakeholders to shape public policy in a manner that benefits Exelon's shareholders and consumers.	2011 Milestone − Submit comments, including expert research, to EPA in support of rule establishing strict national emissions standards for hazardous air pollutants, in accordance with schedule adopted by EPA.	Exceeds
Opportunistic M&A: Participating in industry consolidation – only when the time and price are right.	Considerations − • Was transaction identified and entered into? • Evaluate discipline of transaction, including those not pursued, in its terms & desired outcomes. • How well was the transaction executed? • Post−merger evaluation	Exceeds
Organic Growth: Creating commercial opportunities that leverage Exelon's unique investment platform.	2011 Milestone − • Nuclear uprates executed in accordance with latest approved schedule and budget.	Exceeds
Risk Management: Protecting shareholder and bondholder value through active risk management.	Hedging − Total % of Portfolio Hedged	Exceeds

Total shareholder return data continued to be provided to the compensation committee as a factor that will be taken into account in making the final payout decisions. The total shareholder return data compared Exelon to a group of nine utilities with more than 25% unregulated generation. The committee noted that Exelon's total shareholder return lagged the group, but determined that it was still appropriate to make performance share awards given the importance of the achievement of the performance share goals toward building Exelon's long−term value and the disparate effect of low commodity prices on Exelon's total shareholder return and the distorting effect of mergers and acquisitions activity on the total shareholder return of some of the other companies in the group.

The amount of each NEO's target opportunity was based on the portion of the long−term incentive value for each NEO attributable to performance share units (75%) and a 90−day moving average Exelon stock price for the period before the opportunities were granted.

Based on the committee's assessment of performance under the goals at 115% of target and its determination that Mr. Rowe should have an individual performance multiplier of 110% based on his performance evaluation, 2011 Performance Share Unit Awards for NEOs were as set forth in the following table. The first third of the awarded performance shares vests upon the award date, with the remaining thirds vesting on the date of the compensation committee's January meeting in the next two years.

Exelon, Generation, and PECO	IPM %	Shares	Value
Rowe	110%	118,910	$4,736,185
O'Brien	100	20,700	824,481
Hilzinger	100	10,810	430,562
Barnett	100	6,325	251,925
Pacilio	100	21,265	846,985
Crane	100	39,100	1,557,353
Von Hoene	100	28,750	1,145,113
Pardee	100	23,781	947,197
Adams	100	8,625	343,534
Bonney	100	3,680	146,574
Acevedo	100	1,941	77,310

Table of Contents

ComEd Long−Term Incentive Program

In 2007 the compensation committee recommended, and the ComEd board adopted, a long−term incentive program designed to align the incentive compensation program with ComEd's status as a fully regulated operating company. Accordingly, the program pays out in cash; there is no Exelon equity component to the program. The goals for the program and performance for 2011 are as follows:

Goal	Weight	Performance Cycle Target	2011 Performance
ComEd total cost (O&M and Capital)	25%	Manage controllable costs to be relatively flat year over year through 2013	Below target/above threshold
Outage duration and frequency and safety	25%	By year−end 2012 outage duration should be in the second quartile striving for the first quartile and outage frequency and safety should be in the first quartile	Frequency: distinguished; Duration: above target/below distinguished; Safety: distinguished
Operational performance	15%	Implement an operational performance index by year−end 2011 and integrate it into operational and financial processes for unit cost management and efficiencies by year−end 2012	On target
Employee engagement and communications	10%	Increase employee engagement by 2% each year using a survey index; develop an employee communications survey index and establish appropriate goals for each year	On target
Environmental goals related to ComEd's part of Exelon's 2020 program	25%	By 2013, meet or exceed each of ComEd's annual commitments in support of Exelon 2020	Above target/below distinguished

Based on their evaluation of this performance, and in consideration of the level of long−term incentive payouts at the other Exelon operating companies, the compensation committee recommended and the ComEd board approved payouts to participants for 2011 that represented 115% of each participant's target opportunity.

Based on the formula and the exercise of discretion to cap the awards, 2011 ComEd Long−Term Incentive Awards for NEOs were as set forth in the following table. The first third of the award vests upon the award date, with the remaining thirds vesting on the date of the compensation committee's January meeting in the next two years.

ComEd	Value
Clark	$1,092,500
Trpik	333,500
Pramaggiore	690,000
Donnelly	460,000
O'Neill	333,500

Retention and Recognition Awards

In conjunction with his salary increase that was approved at the May 2, 2011 meeting of the committee, as discussed above, the committee granted Mr. Pacilio 50,000 shares of Exelon common stock that will vest on May 2, 2016. In recognition of their leadership in legislative and regulatory matters, the committee recommended at its November 28, 2011 meeting, and the ComEd board of directors approved, cash recognition awards to Mr. O’Neill in the amount of $100,000 and to Messrs. Donnelly and Trpik in the amount of $75,000 each.

Recoupment Policy

Consistent with the pay−for−performance policy, in May 2007, the board of directors adopted a recoupment policy as part of Exelon’s corporate governance principles. The board of directors will seek recoupment of incentive compensation paid to an executive officer if the board determines, in its sole discretion, that

- the executive officer engaged in fraud or intentional misconduct;
- as a result of which Exelon was required to materially restate its financial results;
- the executive officer was paid more incentive compensation than would have been payable had the financial results been as restated;
- recoupment is not precluded by applicable law or employment agreements; and
- the board concludes that, under the facts and circumstances, seeking recoupment would be in the best interest of Exelon and its shareholders.

Tax Consequences

Under Section 162(m) of the Code, executive compensation in excess of $1 million paid to a CEO or other person among the four other highest compensated officers is generally not deductible for purposes of corporate Federal income taxes. However, qualified performance−based compensation, within the meaning of Section 162(m) and applicable regulations, remains deductible. The compensation committee intends to continue reliance on performance−based compensation programs, consistent with sound executive compensation policy. The compensation committee’s policy has been to seek to cause executive incentive compensation to qualify as “performance−based” in order to preserve its deductibility for Federal income tax purposes to the extent possible, without sacrificing flexibility in designing appropriate compensation programs.

Because it is not “qualified performance−based compensation” within the meaning of Section 162(m), base salary is not eligible for a Federal income tax deduction to the extent that it exceeds $1 million. Accordingly, Exelon is unable to deduct that portion of Mr. Rowe’s base salary in excess of $1 million. Annual incentive awards and performance share units payable to NEOs are intended to be qualified performance−based compensation under Section 162(m), and are therefore deductible for Federal income tax purposes. However, because of the element of compensation committee and ComEd board of directors discretion in the ComEd Long−Term Incentive Program, payments under that program are not eligible for Federal income tax deduction to the extent that, combined with an individual’s base salary, payments exceed $1 million. Restricted stock and restricted stock units are not deductible by the company for Federal income tax purposes under the provisions of Section 162(m) if NEOs’ compensation that is not “qualified performance−based compensation” is in excess of $1 million.

Under Section 4999 of the Internal Revenue Code, there is a excise tax if change in control or severance benefits are greater than 2.99 times the five−year average amount of income reported on an individual's W−2. In April 2009 the compensation committee adopted a policy that no future employment or severance agreements that provide for benefits for NEOs on account of termination will include an excise tax gross−up. However, certain NEOs have change in control severance agreements that pre−date April 2009 that provide excise tax gross−ups, and avoid gross−ups by reducing payments to under the threshold if the amount otherwise payable to an executive is not more than 110% of the threshold.

Conclusion

The compensation committee is confident that Exelon's compensation programs are performance−based and consistent with sound executive compensation policy. They are designed to attract, retain and reward outstanding executives and to motivate and reward senior management for achieving high levels of business performance, customer satisfaction and outstanding financial results that build shareholder value.

Compensation Committee Report

The Compensation Committee has reviewed and discussed the Compensation Discussion and Analysis required by Item 402(b) of Regulation S−K with management and, based on such review and discussion, the Compensation Committee recommended to the Board that the Compensation Discussion and Analysis be included in the 2011 Annual Report on Form 10−K and the 2012 Proxy Statement.

February 8, 2012

The Compensation Committee
Rosemarie B. Greco, Chair
John A. Canning, Jr.
M. Walter D'Alessio
William C. Richardson
Stephen D. Steinour

Table of Contents

Summary Compensation Table

The tables below summarize the total compensation paid or earned by each of the NEOs of Exelon, Generation, PECO (shown in one table because of the overlap in their named executive officers) and ComEd for the year ended December 31, 2011.

Salary amounts may not match the amounts discussed in Compensation Discussion and Analysis because that discussion concerns salary rates; the amounts reported in the Summary Compensation Tables reflect actual amounts paid during the year including the effect of changes in salary rates. Changes to base salary generally take effect on March 1, and there may also be changes at other times during the year to reflect promotions or changes in responsibilities.

Bonus reflects discretionary bonuses or amounts paid under the annual incentive plan on the basis of the individual performance multiplier or discretionary amounts approved by the compensation committee and the board of directors or, in the case of Mr. Rowe, approved by the independent directors.

Stock awards and option awards show the grant date fair value calculated in accordance with FASB ASC Topic 718.

Stock awards consist primarily of performance share awards pursuant to the terms of the 2006 Long−Term Incentive Plan. In 2011, the compensation committee established new goals for performance share awards. The goals included:

- Operational excellence, delivering low cost, clean and reliable energy and operating our facilities safely;
- Financial management, executing cost discipline and optimizing the balance sheet, cash flow, liquidity, and liability management to deliver value return;
- Policy advocacy, engaging with stakeholders to shape public policy to benefit shareholders and consumers;
- Participating in industry consolidation only when the time and price are right;
- Organic growth, creating commercial opportunities that leverage Exelon's unique investment platform, such as the nuclear uprate program; and
- Protecting shareholder and bondholder value through active risk management.

In connection with the realignment of goals and the changes in the mix of long−term incentives, the compensation committee determined that it would be advisable to reduce the maximum payout for performance shares from 200% of target to 125% of target, while raising the payout at threshold from 50% to 75%. The 125% of target maximum may be increased, in individual cases, if a participant is awarded an individual performance multiplier, which can be up to 10% for senior vice presidents and above and 20% for vice presidents. The compensation committee also approved two changes to the terms of performance shares. First, there will be a restriction on the sale of any performance shares from a grant for a senior vice president or above until all of the shares from the grant have vested three years after the grant date. Second, all awards will be settled in shares, ending the current practice of settling performance shares in cash if the officer has achieved certain stock ownership thresholds. These changes are intended to further align the interests of recipients with shareholders by increasing the amount of incentive compensation paid in stock and by requiring senior officers to hold the stock for a longer period of time.

Prior to 2011, the performance share unit award program was based on total shareholder return for Exelon as compared to the companies in the Standard & Poor's 500 Index and the Dow Jones

Utility Index for a three−year period. The threshold, target and distinguished goals for performance unit share awards are established on the grant date (generally the date of the first compensation committee meeting in the fiscal year). The actual performance against the goals and the number of performance unit share awards are established on the award date (generally the date of the first compensation committee meeting after the completion of the fiscal year). Upon retirement or involuntary termination without cause, earned but non−vested shares are eligible for accelerated vesting. The form of payment provides for payment in Exelon common stock to executives with lower levels of stock ownership, with increasing portions of the payments being made in cash as executives' stock ownership levels increase in excess of the ownership guidelines. If an executive achieves 125% or more of the applicable ownership target, performance shares will be paid half in cash and half in stock. If executive vice presidents and above achieve 200% or more of their applicable stock ownership target, their performance shares will be paid entirely in cash.

In limited cases, the compensation committee has determined that it is necessary to grant restricted shares of Exelon common stock or restricted stock units to executives as a means to recruit and retain talent. They may be used for new hires to offset annual or long−term incentives that are forfeited from a previous employer. They are also used as a retention vehicle and are subject to forfeiture if the executive voluntarily terminates, and in some cases may incorporate performance criteria as well as time−based vesting. When awarded, restricted stock or stock units are earned by continuing employment for a pre−determined period of time or, in some instances, after certain performance requirements are met. In some cases, the award may vest ratably over a period; in other cases, it vests in full at one or more pre−determined dates. Amounts of restricted shares held by each NEO, if any, are shown in the footnotes to the Outstanding Equity Table.

All option awards are made pursuant to the terms of the 2006 Long−Term Incentive Plan. All options are granted at a strike price that is not less than the fair market value of a share of stock on the date of grant. Fair market value is defined under the plans as the closing price on the grant date as reported on the New York Stock Exchange. Individuals receiving stock options are provided the right to buy a fixed number of shares of Exelon common stock at the closing price of such stock on the grant date. The target for the number of options awarded is determined by the portion of the long−term incentive value attributable to stock options and a theoretical value of each option determined by the compensation committee using a lattice binomial ratio valuation formula. Options vest in equal annual installments over a four−year period and have a term of ten years. Employees who are retirement eligible are eligible for accelerated vesting upon retirement or termination without cause. Time vesting adds a retention element to the stock option program. All grants to the NEOs must be approved by the full board of directors, which acts after receiving a recommendation from the compensation committee, except grants to Mr. Rowe, which must be approved by the independent directors, who act after receiving recommendation from the compensation committee.

Non−equity incentive plan compensation includes the amounts earned under the annual incentive plan by the extent to which the applicable financial and operational goals were achieved and, for ComEd NEOs, amounts paid under the ComEd Long Term Incentive Program. The amount of the annual incentive target opportunity is expressed as a percentage of the officer's or employee's base salary, and actual awards are determined using the base salary at the end of the year. Threshold, target and distinguished (i.e. maximum) achievement levels are established for each goal. Threshold is set at the minimally acceptable level of performance, for a payout of 50% of target. Target is set consistent with the achievement of the business plan objectives. Distinguished is set at a level that significantly exceeds the business plan and has a low probability of payout, and is capped at 200% of target. Awards are interpolated to the extent performance falls between the threshold, target, and distinguished levels. For 2010, the payout scales were temporarily recalibrated, with threshold paying out at 25%, plan paying out at 50%, target paying out at 100%, and distinguished paying out at 200%.

Summary Compensation Table

Name and Principal Position (A)	Year (B)	Salary ($) (C)	Bonus ($) See Note 17 (D)	Stock Awards ($) See Note 18 (E)	Option Awards ($) See Note 19 (F)	Non−Equity Incentive Plan Compensation ($) See Note 20 (G)	Change in Pension Value and Nonqualified Deferred Compen−sation Earnings ($) See Note 21 (H)	All Other Compen−sation ($) See Note 22 (I)	Total ($) (J)
Rowe (1)	2011	$1,512,904	$ —	$4,079,600	$1,648,300	$ 2,500,000	$1,505,192	$470,008	$11,716,004
	2010	1,475,000	—	1,070,210	1,115,040	2,474,313	2,878,315	405,521	9,418,399
	2009	1,468,077	—	6,341,383	2,236,650	1,573,825	173,566	416,947	12,210,448
O'Brien (2)	2011	555,292	—	781,200	304,780	575,172	145,395	44,344	2,406,183
	2010	536,000	63,177	212,060	218,160	631,768	213,789	28,712	1,903,666
	2009	532,923	—	1,255,539	443,001	395,970	233,772	55,464	2,916,669
Hilzinger (3)	2011	472,954	—	407,960	161,720	402,060	80,484	37,035	1,562,213
	2010	446,000	18,962	103,057	107,464	379,245	88,452	20,465	1,163,645
	2009	442,769	13,079	609,573	215,007	261,579	85,891	31,725	1,659,623
Barnett (4)	2011	317,617	7,500	238,700	93,300	216,709	50,030	21,490	945,346
	2010	309,900	12,435	65,402	67,064	248,695	59,205	11,876	774,577
	2009	307,996	—	382,121	135,642	153,788	55,038	23,407	1,057,992
Pacilio (5)	2011	613,000	35,799	2,877,394	161,720	715,982	1,132,392	37,566	5,573,853
	2010	450,946	—	539,468	84,840	385,316	998,116	23,211	2,481,897
Crane (6)	2011	858,692	—	1,475,600	584,680	1,136,857	1,430,802	75,513	5,562,144
	2010	825,000	—	396,374	428,240	1,132,313	1,621,679	87,155	4,490,761
	2009	821,154	—	2,049,674	707,070	680,213	719,399	76,140	5,053,650
Von Hoene (7)	2011	621,058	—	1,085,000	416,740	616,071	110,241	77,761	2,926,871
	2010	600,000	—	251,697	266,640	686,250	123,906	35,190	1,963,683
Pardee (8)	2011	653,527	—	889,954	273,680	704,889	558,698	44,452	3,125,200
	2010	588,585	—	473,623	180,992	485,705	449,842	23,651	2,202,398
	2009	568,615	16,903	1,028,086	363,636	338,052	221,082	33,192	2,569,566
Adams (9)	2011	351,449	—	325,500	130,620	289,759	101,441	7,646	1,206,415
	2010	332,800	29,378	81,257	84,840	293,779	160,420	8,531	991,005
	2009	330,339	16,515	482,200	168,831	165,152	190,121	4,100	1,357,258
Bonney (10)	2011	318,299	16,217	277,760	—	174,344	308,568	17,549	1,112,737
	2010	306,000	19,645	57,474	59,792	196,452	206,962	10,049	856,374
	2009	284,586	—	336,630	119,769	121,482	337,150	14,840	1,214,457
Acevedo (11)	2011	223,813	—	146,518	—	102,232	30,466	13,895	516,924
	2010	216,000	—	29,728	30,704	107,141	34,247	7,082	424,902
	2009	212,208	3,695	119,356	—	73,899	33,958	10,610	453,726

Table of Contents

ComEd

Summary Compensation Table

Name and Principal Position (A)	Year (B)	Salary ($) (C)	Bonus ($) See Note 17 (D)	Stock Awards ($) See Note 18 (E)	Option Awards ($) See Note 19 (F)	Non−Equity Incentive Plan Compensation ($) See Note 20 (G)	Change in Pension Value and Nonqualified Deferred Compen−sation Earnings ($) See Note 21 (H)	All Other Compen−sation ($) See Note 22 (I)	Total ($) (J)
Clark (12)	2011	$586,373	$ —	$ —	$ —	$ 1,681,714	$ 282,606	$ 52,949	$2,603,642
	2010	567,000	39,016	—	—	437,519	928,222	32,315	2,004,072
	2009	564,385	—	254,300	—	1,461,250	180,950	85,888	2,546,773
Trpik (13)	2011	296,846	75,000	—	—	513,260	45,363	25,278	955,747
	2010	280,000	18,620	—	—	129,635	49,626	15,644	493,525
	2009	263,810	6,300	172,864	62,049	257,556	51,563	27,312	841,454
Pramaggiore (14)	2011	444,481	—	—	—	1,079,481	79,202	24,464	1,627,628
	2010	415,000	54,978	—	—	277,533	86,673	17,158	851,342
	2009	391,269	24,900	—	—	776,342	89,876	33,774	1,316,161
Donnelly (15)	2011	359,265	75,000	—	—	724,381	81,290	32,319	1,272,255
	2010	350,000	28,448	—	—	198,054	114,239	20,934	711,675
	2009	326,154	9,625	—	—	574,610	134,917	35,392	1,080,698
O'Neill (16)	2011	338,423	100,000	—	—	559,865	53,259	28,719	1,080,266
	2010	315,000	24,384	65,402	67,064	169,760	57,974	14,734	714,318

Notes to the Summary Compensation Tables

(1) John W. Rowe, Chairman and CEO, Exelon; Chairman, Generation.
(2) Denis P. O'Brien, Executive Vice President, Exelon; President and CEO, PECO.
(3) Matthew F. Hilzinger, Senior Vice President and Chief Financial Officer, Exelon and Generation.
(4) Phillip S. Barnett, Senior Vice President and Chief Financial Officer, PECO.
(5) Michael J. Pacilio, President, Exelon Nuclear and Chief Nuclear Officer, Generation.
(6) Christopher M. Crane, President and Chief Operating Officer, Exelon and Generation.
(7) William A. Von Hoene, Executive Vice President, Finance and Legal, Exelon.
(8) Charles G. Pardee, Senior Vice President and Chief Operating Officer, Generation.
(9) Craig L. Adams, Senior Vice President & Chief Operating Officer, PECO.
(10) Paul R. Bonney, Vice President, Regulatory Affairs and General Counsel, PECO.
(11) Jorge A. Acevedo, Vice President and Controller, PECO.
(12) Frank M. Clark, Chairman and CEO, ComEd.
(13) Joseph R. Trpik, Jr., Senior Vice President, Chief Financial Officer and Treasurer, ComEd.
(14) Anne R. Pramaggiore, President and Chief Operating Officer, ComEd.
(15) Terence R. Donnelly, Executive Vice President, Operations, ComEd.
(16) Thomas S. O'Neill, Senior Vice President, Regulatory and Energy Policy and General Counsel, ComEd.
(17) In recognition of their overall performance, certain NEOs received an individual performance multiplier to their annual incentive payments or other special recognition awards in certain years. In addition, five NEOs received discretionary cash recognition awards as described in the CD&A above.
(18) The amounts shown in this column include the aggregate grant date fair value of stock awards granted on January 24, 2011 with respect to the performance period ending December 31, 2011. The grant date fair value of the stock award have been computed in accordance with FASB ASC Topic 718 using the assumptions described in Note 16 of the Combined Notes to Consolidated Financial Statements. For the 2011 grants for Messrs. Rowe, O'Brien, Hilzinger, Barnett, Pacilio, Crane, Von Hoene Jr., Pardee, Adams, Bonney, and Acevedo the grant date fair value of their awards assuming that the highest level of performance conditions would be achieved was $5,609,450, $1,074,150, $560,945, $328,213, $1,083,354, $2,028,950, $1,491,875, $1,223,687, $447,563, $208,320, and $109,889, respectively.
(19) The amounts shown in this column include the aggregate grant date fair value of stock option awards granted on January 24, 2011. The grant date fair value of the stock options award have been computed in accordance with FASB ASC Topic 718 using the assumptions described in Note 16 of the Combined Notes to Consolidated Financial Statements.

Table of Contents

(20) The amounts shown in this column represent payments made pursuant to the Annual Incentive Plan and the ComEd Long−Term Incentive Plan. Both programs are paid with respect to 2011 performance and were awarded on January 24, 2011. The table below details ComEd Employee's payments applicable to the ComEd Annual Incentive Plan and the ComEd Long−Term Incentive Plan.

(21) The amounts shown in the column represent the change in the accumulated pension benefit from December 31, 2010 to December 31, 2011. No NEOs had above market earnings in a Nonqualified Deferred Compensation account.

(22) The amounts shown in this column include the items summarized in the following tables:

Name	Year	Annual Incentive Plan	ComEd Long−Term Incentive Plan	Total
Clark	2011	$ 589,214	$1,092,500	$1,681,714
	2010	437,519	—	437,519
	2009	425,250	1,036,000	1,461,250
Trpik	2011	179,760	333,500	513,260
	2010	129,635	—	129,635
	2009	126,000	131,556	257,556
Pramaggiore	2011	389,481	690,000	1,079,481
	2010	277,533	—	277,533
	2009	249,000	527,342	776,342
Donnelly	2011	264,381	460,000	724,381
	2010	198,054	—	198,054
	2009	192,500	382,110	574,610
O'Neill	2011	226,365	333,500	559,865
	2010	169,760	—	169,760

Exelon, Generation and PECO
All Other Compensation

Name (a)	Perquisites ($) See Note 1 (b)	Reimburse−ment for Income Taxes ($) See Note 2 (c)	Payments or Accruals for Termination or Change in Control (CIC) ($) See Note 3 (d)	Company Contributions to Savings Plans ($) See Note 4 (e)	Company Paid Term Life Insurance Premiums ($) See Note 5 (f)	Dividends or Earnings not included in Grants ($) (g)	Total ($) (h)
Rowe	$ 221,980	$ 18,404	$ —	$ 89,637	$139,987	$ —	$470,008
O'Brien	3,201	1,495	—	32,739	6,909	—	44,344
Hilzinger	3,000	2,381	—	27,569	4,085	—	37,035
Barnett	—	—	—	18,825	2,665	—	21,490
Pacilio	—	1,081	—	31,918	4,567	—	37,566
Crane	6,735	5,402	—	50,511	12,865	—	75,513
Von Hoene	19,733	15,435	—	36,633	5,960	—	77,761
Pardee	—	2,427	—	37,264	4,761	—	44,452
Adams	1,166	1,340	—	—	5,140	—	7,646
Bonney	—	—	—	14,700	2,849	—	17,549
Acevedo	—	39	—	13,194	662	—	13,895

Table of Contents

ComEd

All Other Compensation

Name (a)	Perquisites ($) See Note 1 (b)	Reimburse−ment for Income Taxes ($) See Note 2 (c)	Payments or Accruals for Termination or Change in Control (CIC) ($) See Note 3 (d)	Company Contributions to Savings Plans ($) See Note 4 (e)	Company Paid Term Life Insurance Premiums ($) See Note 5 (f)	Dividends or Earnings not included in Grants ($) (g)	Total ($) (h)
Clark	$ 9,546	$ 767	$ —	$ 34,602	$ 8,034	$ —	$52,949
Trpik	6,000	230	—	17,305	1,743	—	25,278
Pramaggiore	6,480	1,760	—	11,232	4,992	—	24,464
Donnelly	6,480	495	—	21,278	4,066	—	32,319
O'Neill	6,000	312	—	19,603	2,804	—	28,719

Notes to All Other Compensation Tables

(1) The amounts shown in this column represent the incremental cost to Exelon to provide certain perquisites to NEOs as summarized in the Perquisites Table below.
(2) Officers receive a reimbursement to cover applicable taxes on imputed income for business−related spousal travel expenses for those cases where the personal benefit is closely related to the business purpose.
(3) Represents the expense, if applicable, or the accrual of the expense that Exelon has recorded during 2011 after the announcement of the officer's retirement or resignation for severance related costs including salary and Annual Incentive Plan (AIP) continuation, outplacement fees, medical benefits, and a prorated portion of his cash retention award.
(4) Represents company matching contributions to the NEO's qualified and non−qualified savings plans. The 401(k) plan is available to all employees and the annual contribution for 2011 was generally limited by IRS rules to $16,500. NEOs and other officers may participate in the Deferred Compensation Plan, into which payroll contributions in excess of the specified IRS limit are credited under the separate, unfunded plan that has the same portfolio of investment options as the 401(k) plan.
(5) Exelon provides basic term life insurance, accidental death and disability insurance, and long−term disability insurance to all employees, including NEOs. The values shown in this column include the premiums paid during 2011 for additional term life insurance policies for the NEOs, additional supplemental accidental death and dismemberment insurance and for additional long−term disability insurance over and above the basic coverage provided to all employees. Mr. Rowe has two term life insurance policies and one additional accidental death and dismemberment policy.

Exelon, Generation and PECO

Perquisites

Name (a)	Personal and Spouse Travel ($) See Note 1 & Note 2 (b)	Parking ($) See Note 3 (c)	Other Items ($) See Note 4 (d)	Total ($) (e)
Rowe	$ 218,980	$ 3,000	$ —	$221,980
O'Brien	1,201	—	2,000	3,201
Hilzinger	—	3,000	—	3,000
Barnett	—	—	—	—
Pacilio	—	—	—	—
Crane	3,735	3,000	—	6,735
Von Hoene	16,198	3,000	535	19,733
Pardee	—	—	—	—
Adams	1,166	—	—	1,166
Bonney	—	—	—	—
Acevedo	—	—	—	—

Table of Contents
ComEd

Perquisites

Name (a)	Personal and Spouse Travel ($) See Note 1 & Note 2 (b)	Parking ($) See Note 3 (c)	Other Items ($) See Note 4 (d)	Total ($) (e)
Clark	$ 66	$ 9,480	$ —	$9,546
Trpik	—	6,000	—	6,000
Pramaggiore	—	6,480	—	6,480
Donnelly	—	6,480	—	6,480
O’Neill	—	6,000	—	6,000

Note to Perquisite Tables

(1) Mr. Rowe is entitled to up to 60 hours of personal use of corporate aircraft each year. Mr. Crane was also permitted to use the corporate aircraft on one occasion during 2011 to return him to a family holiday vacation from which he was called away to attend to Exelon business. The figures shown in this column include $211,558 and $1,826 representing the aggregate incremental cost to Exelon for personal use of corporate aircraft by Mr. Rowe and Mr. Crane respectively. These costs were calculated using the hourly cost for flight services paid to the aircraft vendor, Federal excise tax, fuel charges, and domestic segment fees. From time to time Mr. Rowe’s spouse accompanies Mr. Rowe in his travel on corporate aircraft. The aggregate incremental cost to the company, if any, for Mrs. Rowe’s travel on corporate aircraft is included in this amount. For all executive officers, including Mr. Rowe, Exelon pays the cost of spousal travel, meals, and other related amenities when they attend company or industry−related events where it is customary and expected that officers attend with their spouses. The aggregate incremental cost to Exelon for these expenses is included in the table. In most cases, there is no incremental cost to Exelon of providing transportation or other amenities for a spouse, and the only additional cost to Exelon is to reimburse officers for the taxes on the imputed income attributable to their spousal travel, meals, and related amenities when attending company or industry−related events. This cost is shown in column (b) of the All Other Compensation Table above.

(2) The company maintains several cars and drivers in order to provide transportation services for the NEOs and other officers to carry out their duties among the company’s various offices and facilities which are located throughout northeastern Illinois and southeastern Pennsylvania. Messrs. Rowe, Clark, and O’Brien are also entitled to limited personal use of the company’s cars and drivers, including use for commuting which allows them to work while commuting. The cost included in the table represents the estimated incremental cost to Exelon to provide limited personal service. This cost is based upon the number of hours that the drivers worked overtime providing services to each NEO, multiplied by the average overtime rate for drivers plus an additional amount for fuel and maintenance. Personal use was imputed as additional taxable income to Messrs. Rowe, Clark, and O’Brien.

(3) For NEOs whose primary work location is downtown Chicago or Washington D.C. Exelon’s office lease provides for a limited number of parking spaces that are available for Exelon use. When NEOs are unable to utilize the available spaces, Exelon provides reimbursement for parking expenses incurred at other public garages.

(4) Executive officers may use company−provided vendors for comprehensive physical examinations and related follow−up testing. Executives also receive certain gifts during the year in recognition of their services that are imputed to the officer as additional taxable income.

Table of Contents

Exelon, Generation and PECO

Grants of Plan Based Awards

Name (a)	Grant Date (b)	Estimated Possible Payouts Under Non−Equity Incentive Plan Awards (See Note 1) Thres−hold ($) (c)	Plan ($) (d)	Maxi−mum ($) (e)	Estimated Possible Payouts Under Equity Incentive Plan Awards (See Note 2) Thres−hold (#) (f)	Target (#) (g)	Maxi−mum (#) (h)	All other Stock Awards: Number of Shares or Units (See Note 3) (#) (i)	All Other Options Awards: Number of Securities Under−lying Options (#) (j)	Exercise or base Price of Option Awards. ($) (k)	Grant Date Fair Value of Stock and Option Awards (See Note 4) ($) (l)
Rowe	24 Jan.2011	$950,000	$1,900,000	$3,800,000							
	24 Jan.2011				70,500	94,000	129,250				4,079,600
	24 Jan.2011								265,000	43.40	1,648,300
O'Brien	24 Jan.2011	210,000	420,000	840,000							
	24 Jan.2011				13,500	18,000	24,750				781,200
	24 Jan.2011								49,000	43.40	304,780
Hilzinger	24 Jan.2011	155,350	310,700	621,400							
	24 Jan.2011				7,050	9,400	12,925				407,960
	24 Jan.2011								26,000	43.40	161,720
Barnett	24 Jan.2011	79,875	159,750	319,500							
	24 Jan.2011				4,125	5,500	7,563				238,700
	24 Jan.2011								15,000	43.40	93,300
Pacilio	24 Jan.2011	160,875	321,750	643,500							
	2 May.2011	92,250	184,500	369,000							
	24 Jan.2011				7,050	9,400	12,925				407,960
	2 May.2011				6,819	9,092	12,502				379,955
	24 Jan.2011								26,000	43.40	161,720
	2 May.2011							50,000		41.79	2,089,500
Crane	24 Jan.2011	432,500	865,000	1,730,000							
	24 Jan.2011				25,500	34,000	46,750				1,475,600
	24 Jan.2011								94,000	43.40	584,680
Von Hoene	24 Jan.2011	234,375	468,750	937,500							
	24 Jan.2011				18,750	25,000	34,375				1,085,000
	24 Jan.2011								67,000	43.40	416,740
Pardee	24 Jan.2011	216,300	432,600	865,200							
	2 May.2011	36,825	73,650	147,300							
	24 Jan.2011				12,000	16,000	22,000				694,400
	2 May.2011				3,509	4,679	6,434				195,535
	24 Jan.2011								44,000	43.40	273,680
Adams	24 Jan.2011	106,800	213,600	427,200							
	24 Jan.2011				5,625	7,500	10,313				325,500
	24 Jan.2011								21,000	43.40	130,620
Bonney	24 Jan.2011	64,260	128,520	257,040							
	24 Jan.2011				2,400	3,200	4,800				138,880
	24 Jan.2011							3,200		43.40	138,880
Acevedo	24 Jan.2011	39,501	79,002	158,004							
	24 Jan.2011				1,266	1,688	2,532				73,259
	24 Jan.2011							1,688		43.40	73,259

Table of Contents

ComEd

Grants of Plan Based Awards

Name (a)	Grant Date (b)		Estimated Possible Payouts Under Non−Equity Incentive Plan Awards (See Note 1) Thres−hold ($) (c)	Plan ($) (d)	Maxi−mum ($) (e)	Estimated Possible Payouts Under Equity Incentive Plan Awards (See Note 2) Thres−hold (#) (f)	Target (#) (g)	Maxi−mum (#) (h)	All other Stock Awards: Number of Shares or Units (See Note 3) (#) (i)	All Other Options Awards: Number of Securities Under−lying Options (#) (j)	Exercise or base Price of Option Awards. ($) (k)	Grant Date Fair Value of Stock and Option Awards (See Note 4) ($) (l)
Clark	24 Jan.2011	CE LTI	$475,000	$950,000	$1,900,000							
	24 Jan.2011	AIP	221,250	442,500	885,000							
Trpik	24 Jan.2011	CE LTI	145,000	290,000	580,000							
	24 Jan.2011	AIP	67,500	135,000	270,000							
Pramaggiore	24 Jan.2011	CE LTI	300,000	600,000	1,200,000							
	24 Jan.2011	AIP	146,250	292,500	585,000							
Donnelly	24 Jan.2011	CE LTI	200,000	400,000	800,000							
	24 Jan.2011	AIP	99,275	198,550	397,100							
O’Neill	24 Jan.2011	CE LTI	145,000	290,000	580,000							
	24 Jan.2011	AIP	85,000	170,000	340,000							

Notes to Grants of Plan Based Awards Tables

(1) All NEOs have annual incentive plan target opportunities based on a fixed percentage of their base salary. ComEd NEOs have a long−term incentive plan target based on a cash target (for the ComEd NEOs, the rows labeled “CE LTI” are for the long−term incentive, and the rows labeled “AIP” are for the annual incentive). Under the terms of both incentive plans, threshold performance earns 50% of the respective target, while performance at plan earns 100% of the respective target and the maximum payout is capped at 200% of target. For additional information about the terms of these programs, see Compensation Discussion and Analysis above.

(2) Non−ComEd NEOs have a long−term performance share target opportunity that is a fixed number of performance shares commensurate with the officer’s position. For additional information about the terms of these programs, see Compensation Discussion and Analysis and the narrative preceding the Summary Compensation Table above.

(3) This column shows additional restricted share awards made during the year. The vesting dates of the awards are provided in the footnote 2 to the Outstanding Equity Table below.

(4) This column shows the grant date fair value, calculated in accordance with FASB ASC Topic 718, of the performance share awards, stock options, and restricted stock granted to each NEO during 2011. Fair value of performance share awards granted on January 24, 2011 is based on an estimated payout of 100% of target. Fair value of performance share awards granted on May 2, 2011 is based on an estimated payout of 100% of target.

Exelon, Generation and PECO

Outstanding Equity Awards at Year End

	Options (See Note 1)					Stock (See Note 2)			
Name (a)	Number of Securities Underlying Unexercised Options That Are Exercisable (#) (b)	Number of Securities Underlying Unexercised Options That Are Not Exercisable (#) (c)	Option Exercise or Base Price ($) (d)	Option Grant Date (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Yet Vested (#) (g)	Market Value of Share or Units of Stock That Have Not Yet Vested Based on 12/31 Closing Price $43.37 ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Yet Vested (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Yet Vested ($) (j)
Rowe	—	265,000	$ 43.40	24-Jan-2011	23-Jan-2021	21,697	$ 940,999	94,000	$4,076,780
	34,500	103,500	46.09	25-Jan-2010	24-Jan-2020				
	77,500	77,500	56.51	26-Jan-2009	25-Jan-2019				
	85,500	28,500	73.29	28-Jan-2008	27-Jan-2018				
	150,000	—	59.96	22-Jan-2007	21-Jan-2017				
	229,000	—	42.85	24-Jan-2005	23-Jan-2015				
O'Brien	—	49,000	43.40	24-Jan-2011	23-Jan-2021	4,298	186,404	18,000	780,660
	6,750	20,250	46.09	25-Jan-2010	24-Jan-2020				
	15,350	15,350	56.51	26-Jan-2009	25-Jan-2019				
	16,500	5,500	73.29	28-Jan-2008	27-Jan-2018				
	19,000	—	59.96	22-Jan-2007	21-Jan-2017				
	20,000	—	58.55	23-Jan-2006	22-Jan-2016				
	29,000	—	42.85	24-Jan-2005	23-Jan-2015				
	30,000	—	32.54	26-Jan-2004	25-Jan-2014				
	30,000	—	24.81	27-Jan-2003	26-Jan-2013				
Hilzinger	—	26,000	43.40	24-Jan-2011	23-Jan-2021	7,088	307,407	9,400	407,678
	3,325	9,975	46.09	25-Jan-2010	24-Jan-2020				
	7,450	7,450	56.51	26-Jan-2009	25-Jan-2019				
	8,250	2,750	73.29	28-Jan-2008	27-Jan-2018				
	10,500	—	59.96	22-Jan-2007	21-Jan-2017				
	10,500	—	58.55	23-Jan-2006	22-Jan-2016				
	14,000	—	42.85	24-Jan-2005	23-Jan-2015				
	4,500	—	32.54	26-Jan-2004	25-Jan-2014				
Barnett	—	15,000	43.40	24-Jan-2011	23-Jan-2021	1,310	56,815	5,500	238,535
	2,075	6,225	46.09	25-Jan-2010	24-Jan-2020				
	4,700	4,700	56.51	26-Jan-2009	25-Jan-2019				
	5,025	1,675	73.29	28-Jan-2008	27-Jan-2018				
	8,500	—	59.96	22-Jan-2007	21-Jan-2017				
	8,500	—	58.55	23-Jan-2006	22-Jan-2016				
	9,675	—	42.85	24-Jan-2005	23-Jan-2015				
	3,500	—	32.54	26-Jan-2004	25-Jan-2014				
Pacilio	—	26,000	43.40	24-Jan-2011	23-Jan-2021	71,652	3,107,547	18,492	801,998
	2,625	7,875	46.09	25-Jan-2010	24-Jan-2020				
	5,850	5,850	56.51	26-Jan-2009	25-Jan-2019				
	6,225	2,075	73.29	28-Jan-2008	27-Jan-2018				
	6,375	—	59.96	22-Jan-2007	21-Jan-2017				
	4,250	—	58.55	23-Jan-2006	22-Jan-2016				
	3,500	—	42.85	24-Jan-2005	23-Jan-2015				
Crane	—	94,000	43.40	24-Jan-2011	23-Jan-2021	22,043	956,005	34,000	1,474,580
	13,250	39,750	46.09	25-Jan-2010	24-Jan-2020				
	24,500	24,500	56.51	26-Jan-2009	25-Jan-2019				
	21,000	7,000	73.29	28-Jan-2008	27-Jan-2018				
	35,000	—	59.96	22-Jan-2007	21-Jan-2017				
	22,500	—	58.55	23-Jan-2006	22-Jan-2016				
	18,000	—	42.85	24-Jan-2005	23-Jan-2015				
	13,500	—	32.54	26-Jan-2004	25-Jan-2014				

Table of Contents

Name (a)	Options (See Note 1): Number of Securities Underlying Unexercised Options That Are Exercisable (#) (b)	Number of Securities Underlying Unexercised Options That Are Not Exercisable (#) (c)	Option Exercise or Base Price ($) (d)	Option Grant Date (e)	Option Expiration Date (f)	Stock (See Note 2): Number of Shares or Units of Stock That Have Not Yet Vested (#) (g)	Market Value of Share or Units of Stock That Have Not Yet Vested Based on 12/31 Closing Price $43.37 ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Yet Vested (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Yet Vested ($) (j)
Von Hoene	—	67,000	43.40	24–Jan–2011	23–Jan–2021	9,216	399,698	25,000	1,084,250
	8,250	24,750	46.09	25–Jan–2010	24–Jan–2020				
	12,600	12,600	56.51	26–Jan–2009	25–Jan–2019				
	14,250	4,750	73.29	28–Jan–2008	27–Jan–2018				
	19,000	—	59.96	22–Jan–2007	21–Jan–2017				
	17,000	—	58.55	23–Jan–2006	22–Jan–2016				
	14,000	—	42.85	24–Jan–2005	23–Jan–2015				
	4,500	—	32.54	26–Jan–2004	25–Jan–2014				
Pardee	—	44,000	43.40	24–Jan–2011	23–Jan–2021	21,518	933,236	20,679	896,848
	5,600	16,800	46.09	25–Jan–2010	24–Jan–2020				
	12,600	12,600	56.51	26–Jan–2009	25–Jan–2019				
	14,250	4,750	73.29	28–Jan–2008	27–Jan–2018				
	19,000	—	59.96	22–Jan–2007	21–Jan–2017				
	12,750	—	58.55	23–Jan–2006	22–Jan–2016				
	14,500	—	42.85	24–Jan–2005	23–Jan–2015				
	10,000	—	32.54	26–Jan–2004	25–Jan–2014				
Adams	—	21,000	43.40	24–Jan–2011	23–Jan–2021	5,652	245,127	7,500	325,275
	2,625	7,875	46.09	25–Jan–2010	24–Jan–2020				
	5,850	5,850	56.51	26–Jan–2009	25–Jan–2019				
	6,225	2,075	73.29	28–Jan–2008	27–Jan–2018				
	8,500	—	59.96	22–Jan–2007	21–Jan–2017				
	8,500	—	58.55	23–Jan–2006	22–Jan–2016				
	7,000	—	42.85	24–Jan–2005	23–Jan–2015				
	4,500	—	32.54	26–Jan–2004	25–Jan–2014				
Bonney	1,850	5,550	46.09	25–Jan–2010	24–Jan–2020	4,513	195,729	3,200	138,784
	4,150	4,150	56.51	26–Jan–2009	25–Jan–2019				
	4,500	1,500	73.29	28–Jan–2008	27–Jan–2018				
	7,700	—	59.96	22–Jan–2007	21–Jan–2017				
	7,800	—	58.55	23–Jan–2006	22–Jan–2016				
	6,900	—	42.85	24–Jan–2005	23–Jan–2015				
	4,500	—	32.54	26–Jan–2004	25–Jan–2014				
Acevedo	950	2,850	46.09	25–Jan–2010	24–Jan–2020	2,398	104,001	1,688	73,209
	6,700	—	58.55	23–Jan–2006	22–Jan–2016				
	4,100	—	42.85	24–Jan–2005	23–Jan–2015				
	2,000	—	32.54	26–Jan–2004	25–Jan–2014				

Table of Contents
ComEd

Outstanding Equity Awards at Year End

	Options (See Note 1)					Stock (See Note 2)			
Name (a)	Number of Securities Underlying Unexercised Options That Are Exercisable (#) (b)	Number of Securities Underlying Unexercised Options That Are Not Exercisable (#) (c)	Option Exercise or Base Price ($) (d)	Option Grant Date (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Yet Vested (#) (g)	Market Value of Share or Units of Stock That Have Not Yet Vested Based on 12/31 Closing Price $43.37 ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Yet Vested (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Yet Vested ($) (j)
Clark	30,000	—	$ 58.55	23 Jan. 2006	22 Jan. 2016	—	$ —	—	$ —
	36,000	—	42.85	24 Jan. 2005	23 Jan. 2015				
Trpik	2,150	2,150	56.51	26−Jan−2009	25−Jan−2019	349	15,136	—	—
	2,550	850	73.29	28−Jan−2008	27−Jan−2018				
	4,000	—	59.96	22−Jan−2007	21−Jan−2017				
	3,063	—	58.55	23−Jan−2006	22−Jan−2016				
	3,262	—	42.85	24−Jan−2005	23−Jan−2015				
	1,625	—	32.54	26−Jan−2004	25−Jan−2014				
Pramaggiore	5,300	—	58.55	23 Jan. 2006	22 Jan. 2016	4,000	173,480	—	—
	10,150	—	42.85	24 Jan. 2005	23 Jan. 2015				
	11,400	—	32.54	26 Jan. 2004	25 Jan. 2014				
Donnelly	8,500	—	59.96	22−Jan−2007	21−Jan−2017	4,000	173,480	—	—
	6,500	—	58.55	23−Jan−2006	22−Jan−2016				
	10,000	—	42.85	24−Jan−2005	23−Jan−2015				
	13,000	—	32.54	26−Jan−2004	25−Jan−2014				
	13,800	—	24.81	27−Jan−2003	26−Jan−2013				
O'Neill	2,075	6,225	46.09	25−Jan−2010	24−Jan−2020	4,784	207,482	—	—
	4,150	4,150	56.51	26−Jan−2009	25−Jan−2019				
	4,500	1,500	73.29	28−Jan−2008	27−Jan−2018				
	7,700	—	59.96	22−Jan−2007	21−Jan−2017				
	6,500	—	58.55	23−Jan−2006	22−Jan−2016				
	7,250	—	42.85	24−Jan−2005	23−Jan−2015				
	10,000	—	32.54	26−Jan−2004	25−Jan−2014				
	4,000	—	24.81	27−Jan−2003	26−Jan−2013				

Notes to Outstanding Equity Tables

(1) Non−qualified stock options are granted to NEOs pursuant to the company's long−term incentive plans. Grants made prior to 2003 vested in three equal increments, beginning on the first anniversary of the grant date. Grants made in 2003 and thereafter vest in four equal increments, beginning on the first anniversary of the grant date. All grants expire on the tenth anniversary of the grant date. For all data above, the number of shares and exercise prices have been adjusted to reflect the 2 for 1 stock split of May 5, 2004.

(2) The amount shown includes the unvested portion of performance share awards earned with respect to the three−year performance periods ending December 31, 2010 and December 31, 2009, and any unvested restricted stock unit awards as shown in the following table. The amount of shares shown in column (i) represents the target number of performance shares available to each NEO for the performance period ending December 31, 2011. Shares are valued at $43.37, the closing price on December 30, 2011.

Table of Contents

Unvested Restricted Stock or Restricted Stock Units

Name	Grant Date	Number of Restricted Shares	Vesting Dates
Hilzinger	01 Aug. 2008	5,000	01 Aug. 2013
Pacilio	01 Aug. 2008	8,000	01 Aug. 2013
	01 Jun. 2010	12,000	01 Jun. 2015
	02 May 2011	50,000	02 May 2016
Crane	01 Aug. 2008	15,000	01 Aug. 2013
Von Hoene	01 Aug. 2008	5,000	01 Aug. 2013
Pardee	01 Jun. 2010	8,000	01 Jun. 2013
	01 Aug. 2008	10,000	01 Aug. 2013
Adams	01 Aug. 2008	4,000	01 Aug. 2013
Bonney	24 Jan. 2011	3,360	23 Jan. 2012, 21 Jan. 2013
Acevedo	26 Jan. 2009	310	23 Jan. 2012
	24 Jan. 2011	1,773	23 Jan. 2012, 21 Jan. 2013

Name	Grant Date	Number of Restricted Shares	Vesting Dates
Pramaggiore	03 Sep. 2007	4,000	03 Sep. 2012
Donnelly	03 Sep. 2007	4,000	03 Sep. 2012
O'Neill	01 Jul. 2008	3,500	01 Jul. 2012

Exelon, Generation and PECO

Option Exercises and Stock Vested

	Option Awards		Stock Awards (See Note 1)	
Name (a)	Number of Shares Acquired on Exercise (b) (#)	Value Realized on Exercise (c) ($)	Number of Shares Acquired on Vesting (d) (#)	Value Realized on Vesting (e) ($)
Rowe	—	$ —	58,691	$2,547,178
O'Brien	—	—	11,695	507,543
Hilzinger	—	—	5,640	244,797
Barnett	—	—	3,583	155,522
Pacilio (2)	—	—	4,495	195,097
Crane	—	—	31,292	1,346,225
Von Hoene	—	—	10,153	440,626
Pardee	—	—	9,493	412,004
Adams	—	—	4,495	195,097
Bonney (3)	—	—	3,144	136,459
Acevedo	—	—	813	35,281

Table of Contents
ComEd

Option Exercises and Stock Vested

Name (a)	Option Awards: Number of Shares Acquired on Exercise (b) (#)	Option Awards: Value Realized on Exercise (c) ($)	Stock Awards (See Note 1): Number of Shares Acquired on Vesting (d) (#)	Stock Awards (See Note 1): Value Realized on Vesting (e) ($)
Clark (4)	—	$ —	—	$ —
Trpik	—	—	4,353	185,229
Pramaggiore	—	—	—	—
Donnelly (4)	10,000	198,706	—	—
O'Neill	—	—	3,267	141,797

Notes to Option Exercises and Stock Vested Table

(1) Share amounts are generally composed of performance shares that vested on January 24, 2011, which included 1/3 of the grant made with respect to the three−year performance period ending December 31, 2010; 1/3 of the grant made with respect to the three−year performance period ending December 31, 2009, and 1/3 of the grant made with respect to the three−year performance period ending December 31, 2009. Shares were valued at $43.40 upon vesting.
(2) For Mr. Crane, the shares received upon vesting includes 15,000 restricted shares that vested on September 3, 2011 and were valued at $42.61.
(3) For Mr. Acevedo, the shares received upon vesting includes 516 shares from the Key Manager Restricted Stock Unit Program that vested on January 24, 2011 that were valued at $43.40.
(4) For Mr. Trpik and Mr. O'Neill, performance shares that vested were paid out 100% in cash.

Pension Benefits

Exelon sponsors the Exelon Corporation Retirement Program, a traditional defined benefit pension plan that covers certain management employees who commenced employment prior to January 1, 2001 and certain collective bargaining unit employees. The Exelon Corporation Retirement Program includes the Service Annuity System (SAS), which is the legacy ComEd pension plan, and the Service Annuity Plan (SAP), which is the legacy PECO pension plan. Effective January 1, 2001, Exelon also established two cash balance defined benefit pension plans in order to both reduce future retirement benefit costs and provide an option that is portable as the company anticipated a work force that was more mobile than the traditional utility workforce. The cash balance defined benefit pension plans cover management employees and certain collective bargaining unit employees hired on or after such date, as well as certain management employees hired prior to such date who elected to transfer to a cash balance plan. Each of these plans is intended to be tax−qualified under Section 401(a) of the Internal Revenue Code. An employee can participate in only one of the qualified pension plans.

For NEOs participating in the SAS, the annuity benefit payable at normal retirement age is equal to the sum of 1.25% of the participant's earnings as of December 25, 1994, reduced by a portion of the participant's Social Security benefit as of that date, plus 1.6% of the participant's highest average annual pay, multiplied by the participant's years of credited service (up to a maximum of 40 years). For NEOs participating in the SAP, the annuity benefit payable at normal retirement age is equal to the greater of the amount determined under the Career Pay Formula, which is 2% of each year's pensionable pay, and the amount determined under the Final Average Pay Formula, which is the sum of (a) 5% of average earnings, plus 1.2% of average earnings for each year of pension service (up to a maximum of 40 years), and (b) 0.35% of average earnings in excess of covered compensation for each year of pension service (up to a maximum of 40 years). Pension−eligible compensation for the SAS and the SAP's Final Average Pay Formula includes base pay and annual incentive awards.

Pension eligible compensation in the SAP's Career Pay Formula includes base pay, incentive awards and other regular remuneration. Benefits under the SAS and SAP are vested after five years of service.

The "normal retirement age" under both the SAS and the SAP is 65. Each of these plans also offers an early retirement benefit prior to age 65, which is payable if a participant retires after attainment of age 50 and completion of ten years of service. The annual pension payable under each plan is determined as of the early retirement date, reduced by 2% for each year of payment before age 60 to age 58, then 3% for each year before age 58 to age 50. In addition, under the SAS, the early retirement benefit is supplemented prior to age 65 by a temporary payment equal to 80% of the participant's estimated monthly Social Security benefit. The supplemental benefit is partially offset by a reduction in the regular annuity benefit.

Under the cash balance pension plan, a notional account is established for each participant, and the account balance grows as a result of annual benefit credits and annual investment credits. (Employees who participated in the SAS or the SAP prior to January 1, 2001 and elected to transfer to the cash balance plan also have a frozen transferred benefit from the former plan, and received a "transition" credit based on their age, service and compensation at the time of transfer.) Beginning January 1, 2008, the annual benefit credit under the plan is 7.00% of base pay and annual incentive award. For the portion of the account balance accrued beginning January 1, 2008, the annual investment credit is the third segment rate of interest on long−term investment grade corporate bonds, as provided for in Internal Revenue Code Section 430(h)(2)(C)(iii). The Segment Rate will be determined as of November of the year for which the cash balance account receives the investment credit. For the portion of the benefit accrued before January 1, 2008, pending Internal Revenue Service guidance, the annual investment credit is the greater of 4%, or the average for the year of the S&P 500 Index and the applicable interest rate specified in Section 417(e) of the Internal Revenue Code that is used to determine lump sum payments (the interest rate is determined in November of each year). Benefits are vested after three years of service, and are payable in an annuity or a lump sum at any time following termination of employment. Apart from the benefit credits and vesting requirement, and as described above, years of service are not relevant to a determination of accrued benefits under the cash balance pension plans.

The Internal Revenue Code limits to $245,000 the individual 2011annual compensation that may be taken into account under the tax−qualified retirement plan. As permitted by Employee Retirement Income Security Act, Exelon sponsors two supplemental executive retirement plans (or "SERPs") that allow the payment to a select group of management or highly−compensated individuals out of its general assets of any benefits calculated under provisions of the applicable qualified pension plan which may be above these limits. The SERPs offer a lump sum as an optional form of payment, which includes the value of the marital annuity, death benefits and other early retirement subsidies at a designated interest rate. The interest rate applicable for distributions to participants in the SAS in 2011 is 4.42% and for participants in the SAP in 2011 is 2.25%. For participants in the cash balance pension plan, the lump sum is the value of the non−qualified account balance. The values of the lump sum amounts do not include the value of any pension benefits covered under the qualified pension plans, and the methods and assumptions used to determine the non−qualified lump sum amount are different than the assumptions used to generate the present values shown in the tables of benefits to be received upon retirement, termination due to death or disability, involuntary separation not related to a change in control, or upon a qualifying termination following a change in control which appear later in this document.

Under the terms of the SERPs, participants are provided the amount of benefits they would have received under the SAS, SAP or cash balance plan, as applicable, but for the application of the Internal Revenue Code limits. In addition, certain executives previously received grants of additional credited service under a SERP. In particular, Mr. Crane received an additional ten years of credited service through September 28, 2008, the date of his 10 year anniversary, as part of his employment offer that provided one additional year of service credit for each year of employment to a maximum of 10 additional years. Pursuant to his employment agreement first entered into when he joined the Company in 1998, Mr. Rowe is entitled to receive a SERP benefit that, when added to SAS benefit, will be determined as though he had earned 20 years of service on March 16, 1998 and one additional year of service on each anniversary of that date occurring prior to his termination of employment. A portion of Mr. Rowe's benefit may be forfeited upon a termination for "cause" (see below under Potential Payments upon Termination or Change in Control—Employment Agreement with Mr. Rowe).

As of January 1, 2004, Exelon does not grant additional years of credited service to executives under the SERP for any period in which services are not actually performed, except that up to two years of service credits may be provided under severance or change in control agreements first entered into after such date. Service credits previously available under employment, change in control or severance agreements or arrangements (or any successors arrangements) are not affected by this policy.

The amount of the change in the pension value for each of the named executive officers is the amount included in the Summary Compensation Table above in the column headed "Change in Pension Value & Nonqualified Deferred Compensation Earnings." The present value of each NEO's accumulated pension benefit is shown in the following tables. The assumptions used in estimating the present values include the following: for Service Annuity System participants, pension benefits are assumed to begin at each participant's earliest unreduced retirement age; and for cash balance plan participants, pension benefits are assumed to begin at the earliest unreduced age. The lump sum rate amounts are determined using the rate of 5% for SAS participants and 4.0% for SAP participants, both at the assumed retirement age, and the account balance for cash balance pension plan participants. The lump sum amounts are discounted from the assumed retirement date at the applicable discount rates 5.26% as of December 31, 2010 and 4.74% as of December 31, 2011. The applicable mortality table as of December 31, 2010 is the IRS−required mortality table for 2011 funding valuation. The applicable table as of December 31, 2011 is the IRS required mortality table for 2012 funding valuation.

Exelon, Generation and PECO

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
Rowe (Note 1)	SAS	13.80	$ 625,498	—
	SERP	33.80	20,799,780	—
O'Brien	Cash Balance	29.51	861,765	—
	SERP	29.51	866,387	—
Hilzinger	Cash Balance	9.72	192,874	—
	SERP	9.72	314,609	—
Barnett	Cash Balance	8.68	166,826	—
	SERP	8.68	163,591	—
Pacilio	SAS	29.53	1,149,919	—
	SERP	29.53	2,725,773	—
Crane	SAS	13.26	535,000	—
	SERP	23.26	5,634,202	—
Von Hoene	Cash Balance	9.93	192,874	—
	SERP	9.93	435,604	—
Pardee	SAS	11.84	455,127	—
	SERP	11.84	1,463,926	—
Adams	Cash Balance	22.38	848,491	—
	SERP	22.38	626,278	—
Bonney	SAP	22.00	878,063	—
	SERP	22.00	877,613	—
Acevedo	Cash Balance	9.17	170,350	—
	SERP	9.17	29,160	—

ComEd

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
Clark	SAS	40.00	$ 1,959,494	—
	SERP	40.00	5,859,493	—
Trpik	Cash Balance	10.60	212,864	—
	SERP	10.60	104,190	—
Pramaggiore	Cash Balance	13.93	347,652	—
	SERP	13.93	205,563	—
Donnelly	Cash Balance	28.53	743,395	—
	SERP	28.53	242,219	—
O'Neill	Cash Balance	10.36	213,733	—
	SERP	10.36	149,970	—

(1) Based on discount rates prescribed by the SEC proxy disclosure guidelines, Mr. Rowe's nonqualified SERP benefit's present value is $20,799,780. Based on lump sum plan rates for immediate distributions under the non−qualified plan, the comparable lump sum amount applicable for service through December 31, 2011 is $24,245,733. Note that, in any event, payments made upon termination may be delayed for six months in accordance with U.S. Treasury Department guidance.

Deferred Compensation Programs

Exelon offers deferred compensation plans to permit the deferral of certain cash compensation to facilitate tax and retirement planning and satisfaction of stock ownership requirements for executives and key managers. Exelon maintains non−qualified deferred compensation plans that are open to certain highly−compensated employees, including the NEOs.

The Deferred Compensation Plan is a non−qualified plan that permits executives and key managers to defer receipt of base compensation and the company to credit related matching contributions that would have been contributed to the Exelon Corporation Employee Savings Plan (the company's tax−qualified 401(k) plan) but for the applicable limits under the Internal Revenue Code. The Deferred Compensation Plan permits participants to defer taxation of a portion of their income. It benefits the company by deferring the payment of a portion of its compensation expense, thus preserving cash.

The Employee Savings Plan is tax−qualified under Sections 401(a) and 401(k) of the Internal Revenue Code (the "Code"). Exelon maintains the Employee Savings Plan to attract and retain qualified employees, including the NEOs, and to encourage employees to save some percentage of their cash compensation for their eventual retirement. The Employee Savings Plan permits employees to do so, and allows the company to make matching contributions in a relatively tax−efficient manner. The company maintains the excess matching feature of the Deferred Compensation Plan to enable management employees to save for their eventual retirement to the extent they otherwise would have were it not for the limits established by the IRS for purposes of Federal tax policy.

The Stock Deferral Plan is a non−qualified plan that permitted executives to defer performance share units prior to 2007.

In response to declining plan enrollment and the administrative complexity of compliance with Section 409A of the Code, the compensation committee approved amendments to the Deferred Compensation and Stock Deferral Plans at its December 4, 2006 meeting. The amendments cease future compensation deferrals for the Stock Deferral Plan and Deferred Compensation Plan other than the excess Employee Savings Plan contribution deferrals.

The following tables show the amounts that NEOs have accumulated under both the Deferred Compensation Plan and the Stock Deferral Plan. Both plans were closed to new deferrals of base pay (other than excess Employee Savings Plan deferrals), annual incentive payments or performance shares awards in 2007, and participants were granted a one−time election to receive a distribution of their accumulated balance in each plan during 2007. Existing balances will continue to accrue dividends or other earnings until payout upon termination. Balances in the Deferred Compensation Plan will be settled in cash upon the termination event selected by the officer and will be distributed either in a lump sum, or in annual installments. Share balances in the Stock Deferral Plan continue to earn the same dividends that are available to all shareholders, which are reinvested as additional shares in the plan. Balances in the plan are distributed in shares of Exelon stock in a lump sum or installments upon termination of employment.

The Deferred Compensation Plan continues in effect, without change, for those officers who participate in the 401(k) savings plan and who reach their statutory contribution limit during the year. After this limit is reached, their elected payroll contributions and company matching contribution will be credited to their account in the Deferred Compensation Plan. The investment options under the Deferred Compensation Plan consist of a basket of mutual funds benchmarks that mirror those funds available to all employees through the 401(k) plan, with the exception of one benchmark fund that offers a fixed percentage return over a specified market return. Deferred amounts represent unfunded unsecured obligations of the company.

Exelon, Generation and PECO

Nonqualified Deferred Compensation

Name (a)	Executive Contributions in 2011 (b) Note (1)	Registrant Contributions in 2011 (c) Note (2)	Aggregate Earnings in 2011 (d) Note (3)	Aggregate Withdrawals/ Distributions (e)	Aggregate Balance at 12/31/11 (f) Note (4)
Rowe (5)	$ 63,395	$ 74,937	$ 7,511	$ —	$ 617,549
O'Brien	15,515	18,039	59,881	—	1,546,116
Hilzinger	11,398	12,869	(42)	—	89,633
Barnett	31,143	11,985	4,887	—	207,779
Pacilio	44,800	18,165	7,909	—	202,398
Crane	69,369	40,272	20,057	—	452,567
Von Hoene	18,803	21,932	7,847	—	156,693
Pardee	48,853	26,990	12,646	—	295,200

ComEd

Nonqualified Deferred Compensation

Name (a)	Executive Contributions in 2011 (b) Note (1)	Registrant Contributions in 2011 (c) Note (2)	Aggregate Earnings in 2011 (d) Note (3)	Aggregate Withdrawals/ Distributions (e)	Aggregate Balance at 12/31/11 (f) Note (4)
Clark	$ 42,137	$ 24,124	$ 19,526	$ —	$263,727
Trpik (5)	3,111	2,605	498	—	14,508
Donnelly (5)	33,797	13,947	9,859	—	217,750
O'Neill	51,185	14,273	4,938	—	561,702

(1) The full amount shown for executive contributions is included in the base salary figures for each NEO shown above in the Summary Compensation Table.

(2) The full amount shown under registrant contributions is included in the company contributions to savings plans for each NEO shown above in the All Other Compensation Table.

(3) The amount shown under aggregate earnings reflects the NEO's gain or loss based upon the individual allocation of their notional account balance into the basket of mutual fund benchmarks. These gains or losses do not represent current income to the NEO and have not been included in any of the compensation tables shown above.

(4) For all NEOs the aggregate balance (Column F) shown above includes those amounts, both executive contributions and registrant contributions, that have been disclosed either as base salary as described in Note 1 or as company contributions under all other compensation as described in Note 2 for the current fiscal year. Messrs. Adams, Bonney, Acevedo, and Ms. Pramaggiore do not participate in the plan.
In 2007, all participants in the deferred compensation plan were eligible to receive a distribution of their entire account balance in the plan accumulated through December 31, 2006. Messrs. Rowe, Hilzinger, Barnett, Crane, Pardee, Clark, Trpik and Donnelly elected to receive this distribution. Since receiving a distribution of their entire accumulated balance in 2007, all executive contributions which are included in the aggregate balance at fiscal year end have been included in base salary in the Summary Compensation Table for each year, and all registrant contributions that are included in the aggregate balance at fiscal year end have been included in all other compensation in the Summary Compensation Table for each year for each of these NEOs.
For Mr. O'Brien, who did not elect to receive the distribution of his accumulated plan balance in 2007, $875,884, consisting of both executive contributions and registrant contributions has been included in the Summary Compensation Table as either base salary or all other compensation for prior years where he has been included as an NEO.

(5) For Messrs. O'Brien, O'Neill and Donnelly, the amounts shown in column (d) and column (f) also include the aggregate earnings and aggregate balance respectively of their Stock Deferral Plan accounts.

Potential Payments upon Termination or Change in Control

Employment Agreement with Mr. Rowe

Under the third amended and restated employment agreement between Exelon and Mr. Rowe, Mr. Rowe may continue to serve as Chief Executive Officer of Exelon, Chairman of Exelon's board of directors and a member of the board of directors until December 31, 2012.

If, prior to July 1, 2011, Exelon had terminated Mr. Rowe's employment for reasons other than cause, death or disability or Mr. Rowe had terminated his employment for good reason, he would have been eligible for the following benefits:

- a lump sum payment of Mr. Rowe's accrued but unpaid base salary and annual incentive, if any, and a prorated annual incentive for the year in which his employment was terminated based on the lesser of (1) the annual incentive that would have been paid based on actual performance without application of negative discretion to reduce the amount of the award, and (2) the formula annual incentive (i.e., the greater of the annual incentive for the last year ending prior to termination or the average of the annual incentives payable with respect to Mr. Rowe's last three full years of employment);
- a lump sum severance payment equal to his base salary and the formula annual incentive, multiplied by the number of years (including fractional years) remaining until the later of July 1, 2011 or the first anniversary of the termination date;
- continuation of life, disability, accident, health and other active welfare benefits for him and his family for a period equal to the number of years (including fractional years) remaining until the later of July 1, 2011 or the first anniversary of the termination date, followed by post−retirement healthcare coverage for him and his wife for the remainder of their respective lives;
- all exercisable stock options would have remained exercisable until the applicable option expiration date;
- non−vested stock options would have become exercisable and thereafter remain exercisable until the applicable option expiration date;
- previously earned but non−vested performance share units would have vested, consistent with the terms of the performance share unit award program under the LTIP, and he would have received an award based on actual performance for the year in which the termination had occurred; and
- any non−vested restricted stock award would have vested.

If such a termination had occurred within 24 months after a Change in Control of Exelon or within 18 months after a Significant Acquisition, as such terms are described under "Change in Control Employment Agreements and Severance Plan Covering Other Named Executives," or Mr. Rowe had resigned before July 1, 2011 because of the failure to be appointed or elected as Exelon's Chief Executive Officer, Chairman of Exelon's board of directors, and a member of the board of directors, then Mr. Rowe would have received the termination benefits described above except that:

- the annual incentive award described above and payable for the year in which Mr. Rowe's employment terminates would have been paid in full, rather than prorated;
- in determining the amount of such full formula annual incentive and the lump sum severance payment described above, the formula annual incentive would have been the greater of the amount described in the preceding paragraph or the target annual incentive for the year in which his employment was terminated, but not greater than the annual incentive for the year in which the termination had occurred based on actual performance without the application of negative discretion to reduce the amount of the award;

- the SERP benefit would have been determined taking into account the lump sum severance payment, as though it were paid in installments and Mr. Rowe remained employed during the severance period; and
- professional outplacement services would have been provided for up to twelve months.

The term “good reason” means any material breach of the employment agreement by Exelon, including:

- a failure to provide compensation and benefits required under the employment agreement (including a reduction in base salary that is not commensurate with and applied to Exelon’s other senior executives) without Mr. Rowe’s consent;
- causing Mr. Rowe to report to someone other than Exelon’s board of directors;
- any material adverse change in Mr. Rowe’s status, responsibilities or perquisites; or
- any public announcement by Exelon’s board of directors without Mr. Rowe’s consent that Exelon was seeking his replacement, other than with respect to the period following July 1, 2011.

With respect to a termination of employment during the Change in Control or Significant Acquisition periods described above, the following events would have constituted additional grounds for termination for good reason:

- a good faith determination by Mr. Rowe that he was substantially unable to perform, or that there had been a material reduction in, any of his duties, functions, responsibilities or authority;
- the failure of any successor to have assumed his employment agreement;
- a relocation of Exelon’s principal offices by more than 50 miles; or
- a 20% increase in the amount of time that Mr. Rowe must have spent traveling for business outside of the Chicago area.

In the event Mr. Rowe’s employment terminates for cause, all outstanding stock options (whether vested or non−vested), non−vested performance shares and restricted stock will be forfeited.

The term “cause” means any of the following, unless cured within the time period specified in the agreement:

- conviction of a felony or of a misdemeanor involving moral turpitude, fraud or dishonesty;
- willful misconduct in the performance of duties intended to personally benefit the executive; or
- material breach of the agreement (other than as a result of incapacity due to physical or mental illness).

Upon Mr. Rowe’s retirement or his termination of employment due to disability or death:

- Mr. Rowe (or his beneficiary or estate) will receive a prorated annual incentive for the year in which the termination occurs, determined under the method described above for a “good reason” termination;
- all exercisable stock options remain exercisable until the applicable option expiration date;
- non−vested stock options become exercisable and thereafter remain exercisable until the applicable option expiration;
- previously earned but non−vested performance share units vest, consistent with the terms of the performance share award program under the LTIP, and he (or his beneficiary or estate) will receive an award for the year in which the termination occurs;

- any non−vested restricted stock award vests, unless otherwise provided in the grant instrument; and
- he will be entitled to receive post−retirement healthcare coverage for him and his wife for the remainder of their respective lives.

The term “retirement” means:

- Mr. Rowe’s termination of employment prior to July 1, 2011 other than a termination by him for good reason or a termination by the Company with or without cause or upon disability or death;
- Mr. Rowe’s termination of employment on or after July 1, 2011 other than a termination by the Company with cause or upon disability or death.

Upon Mr. Rowe’s retirement or termination of employment for any reason other than cause, disability or death:

- For a period of five years, Mr. Rowe is required to attend board of directors meetings as requested by the board or the then−chairman, attend civic, charitable and corporate events, serve on civic and charitable boards and represent the Company at industry and trade association events as the Company’s representative, and provide the then−chairman or the then−CEO advice or counseling on energy policy issues or strategy, each as mutually agreed;
- The Company is required to provide Mr. Rowe with five years of office and secretarial services.

Mr. Rowe is subject to confidentiality restrictions and to non−competition, non−solicitation and non−disparagement restrictions continuing in effect for two years following his termination of employment, and is required to sign a general release to receive severance payments. If the payments or benefits payable to Mr. Rowe would be subject to excise taxes imposed under Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law, such payments and benefits shall be reduced or eliminated to the extent necessary to avoid such excise taxes unless doing so would leave Mr. Rowe with less after−tax payments and benefits than paying such amounts and the applicable excise taxes. Any payment to Mr. Rowe upon a termination of employment is subject to a six−month delay to the extent required under Section 409A of the Internal Revenue Code, and his agreement will be otherwise interpreted and construed to comply with Section 409A.

Change in control employment agreements and severance plan covering other named executives

Exelon’s change in control and severance benefits policies were initially adopted in January 2001 and harmonized the policies of Exelon’s predecessor companies. In adopting the policies, the compensation committee considered the advice of a consultant who advised that the levels were consistent with competitive practice and reasonable. The Exelon benefits currently include multiples of change in control benefits ranging from two times base salary and annual bonus for corporate and subsidiary vice presidents to 2.99 times base salary and annual bonus for the executive committee and select senior vice presidents other than the CEO. In 2003, the compensation committee reviewed the terms of the Senior Management Severance Plan and revised it to reduce the situations when an executive could terminate and claim severance benefits for “good reason”, clarified the definition of “cause”, and reduced non−change in control benefits for executives with less than two years of service. In December 2004, the compensation committee’s consultant presented a report on competitive practice on executive severance. The competitive practices described in the report were generally comparable to the benefits provided under Exelon’s severance policies. In discussing the compensation consultant’s December 2007 annual report to the committee on compensation trends, the consultant commented that Exelon’s change in control and severance policies were conservative, citing the use of double triggers, and that they remained competitive. In April 2009 the compensation committee adopted a policy that Exelon would not include excise tax gross−up payment provisions in senior executive employment, change in control, or severance plans, programs or agreements that are entered into, adopted or materially amended on or after April 2, 2009 (other than renewals of existing arrangements that are not materially amended or arrangements assumed pursuant to a corporate transaction).

Named executive officers other than Mr. Rowe have entered into individual change in control employment agreements or are covered by the change in control provisions of the Senior Management Severance Plan, which generally protect such executives' position and compensation levels for two years after a change in control of Exelon. The individual agreements are initially effective for a period of two years, and provide for a one−year extension each year thereafter until cancellation or termination of employment. The plan does not have a specific term.

During the 24−month period following a change in control, or, with respect to an executive with an individual agreement, during the 18−month period following another significant corporate transaction affecting the executive's business unit in which Exelon shareholders retain between 60% and $66^{2}/_{3}$% control (a significant acquisition), if a named executive officer resigns for good reason or if the executive's employment is terminated by Exelon other than for cause or disability, the executive is entitled to the following:

- the executive's annual incentive and performance share unit awards for the year in which termination occurs;
- severance payments equal to 2.99 (or 2.0 if the executive does not have an individual agreement) times the sum of (1) the executive's base salary plus (2) the higher of the executive's target annual incentive for the year of termination or the executive's average annual incentive award payments for the two years preceding the termination, but not more than the annual incentive for the year of termination based on actual performance before the application of negative discretion;
- a benefit equal to the amount payable under the SERP determined as if (1) the SERP benefit were fully vested, (2) the executive had 2.99 additional years of age and years of service (2.0 years for executives who first entered into such agreements after 2003 or do not have such agreements) and (3) the severance pay constituted covered compensation for purposes of the SERP;
- a benefit equal to the actuarial equivalent present value of any non−vested accrued benefit under Exelon's qualified defined benefit retirement plan;
- all previously−awarded stock options, performance shares or units, restricted stock, or restricted share units become fully vested, and the stock options remain exercisable until (1) the option expiration date, for options granted before January 1, 2002 or (2) the earlier of the fifth anniversary of his termination date or the option's expiration date, for options granted after that date;
- life, disability, accident, health and other welfare benefit coverage continues during the severance pay period on the same terms and conditions applicable to active employees, followed by retiree health coverage if the executive has attained at least age 50 and completed at least ten years of service (or any lesser eligibility requirement then in effect for regular employees); and
- outplacement services for at least twelve months.

The change in control benefits are also provided if the executive is terminated other than for cause or disability, or terminates for good reason (1) after a tender offer or proxy contest commences, or after

Exelon enters into an agreement which, if consummated, would cause a change in control, and within one year after such termination a change in control does occur, or (2) within two years after a sale or spin−off of the executive's business unit in contemplation of a change in control that actually occurs within 60 days after such sale or spin−off (a disaggregation) if the executive has an individual agreement.

A change in control under the individual change in control employment agreements and the Senior Management Severance Plan generally occurs:

- when any person acquires 20% of Exelon's voting securities;
- when the incumbent members of the Exelon board of directors (or new members nominated by a majority of incumbent directors) cease to constitute at least a majority of the members of the Exelon board of directors;
- upon consummation of a reorganization, merger or consolidation, or sale or other disposition of at least 50% of Exelon's operating assets (excluding a transaction where Exelon shareholders retain at least 60% of the voting power); or
- upon shareholder approval of a plan of complete liquidation or dissolution.

The term good reason under the individual change in control employment agreements generally includes any of the following occurring within two years after a change in control or disaggregation or within 18 months after a significant acquisition:

- a material reduction in salary, incentive compensation opportunity or aggregate benefits, unless such reduction is part of a policy, program or arrangement applicable to peer executives;
- failure of a successor to assume the agreement;
- a material breach of the agreement by Exelon; or
- any of the following, but only after a change in control or disaggregation: (1) a material adverse reduction in the executive's position, duties or responsibilities (other than a change in the position or level of officer to whom the executive reports or a change that is part of a policy, program or arrangement applicable to peer executives) or (2) a required relocation by more than 50 miles.

The term cause under the change in control employment agreements generally includes any of the following:

- refusal to perform or habitual neglect in the performance of duties or responsibilities or of specific directives of the officer to whom the executive reports which are not materially inconsistent with the scope and nature of the executive's duties and responsibilities;
- willful or reckless commission of acts or omissions which have resulted in or are likely to result in a material loss or material damage to the reputation of Exelon or any of its affiliates, or that compromise the safety of any employee;
- commission of a felony or any crime involving dishonesty or moral turpitude;
- material violation of the code of business conduct which would constitute grounds for immediate termination of employment, or of any statutory or common−law duty of loyalty; or
- any breach of the executive's restrictive covenants.

Executives other than Mr. Rowe who have entered into such change in control employment agreements prior to April 2, 2009 (and which have not been materially amended after such date) will be eligible to receive an additional payment to cover excise taxes imposed under Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law, but only if the amount of payments and benefits subject to these taxes exceeds 110% of the safe harbor amount that would not subject the employee to these excise taxes. If the amount does not exceed 110% of the safe harbor amount, then payments and benefits subject to these taxes would be reduced or eliminated to equal the safe harbor amount.

If a named executive officer other than Mr. Rowe resigns for good reason or is terminated by Exelon other than for cause or disability, in each case under circumstances not involving a change in control or similar provision described above, the named executive officer may be eligible for the following non−change in control benefits under the Exelon Corporation Senior Management Severance Plan:

- prorated payment of the executive’s annual incentive and performance share unit awards for the year in which termination occurs;
- for a 15 to 24 month severance period, continued payment of an amount representing base salary and target annual incentive;
- a benefit equal to the amount payable under the SERP determined as if the severance payments were paid as ordinary base salary and annual incentive;
- during the severance period, continuation of health, basic life and other welfare benefits the executive was receiving immediately prior to the severance period on the same terms and conditions applicable to active employees, followed by retiree health coverage if the executive has attained at least age fifty and completed at least ten years of service (or any lesser eligibility requirement then in effect for non−executive employees); and
- outplacement services for at least six months.

Payments under individual agreements entered into after April 2, 2009 or the Senior Management Severance Plan are subject to reduction by Exelon to the extent necessary to avoid imposition of excise taxes imposed by Section 4999 of the Internal Revenue Code on excess parachute payments or under similar state or local law.

The term good reason under the Senior Management Severance Plan means either of the following:

- a material reduction of the executive’s salary (or, with respect to a change in control, incentive compensation opportunity or aggregate benefits) unless such reduction is part of a policy, program or arrangement applicable to peer executives of Exelon or of the business unit that employs the executive; or
- a material adverse reduction in the executive’s position or duties (other than a change in the position or level of officer to whom the executive reports) that is not applicable to peer executives of Exelon or of the executive’s business unit, but excluding under the non non−change in control provisions of the plan any change (1) resulting from a reorganization or realignment of all or a significant portion of the business, operations or senior management of Exelon or of the executive’s business unit or (2) that generally places the executive in substantially the same level of responsibility.

With respect to a change in control, the term good reason under the plan also includes a required relocation of more than 50 miles.

The term cause under the Senior Management Severance Plan has the same meaning as the definition of such term under the individual change in control employment agreements.

Benefits under the change in control employment agreements and the Senior Management Severance Plan are subject to termination upon an executive's violation of his or her restrictive covenants, and incentive payments under the agreements and the plan may be subject to the recoupment policy adopted by the Compensation Committee of the Board of Directors.

Estimated Value of Benefits to be Received Upon Retirement

The following tables show the estimated value of payments and other benefits to be conferred upon the NEOs assuming they retired as of December 31, 2011. These payments and benefits are in addition to the present value of the accumulated benefits from each NEO's qualified and non−qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Nonqualified Deferred Compensation section.

Exelon, Generation and PECO

Name	Cash Payment ($) Note (1)	Value of Unvested Equity Awards ($) Note (2)	Perquisites and Other Benefits ($) Note (4)	Total Value of All Payments and Benefits ($) Note (5)
Rowe	$2,500,000	$5,540,000	$1,500,000	$9,540,000
O'Brien	575,000	1,067,000	—	1,642,000
Hilzinger	—	—	—	—
Barnett	—	—	—	—
Pacilio	716,000	987,000	—	1,703,000
Crane	1,137,000	1,973,000	—	3,110,000
Von Hoene	—	—	—	—
Pardee	705,000	1,169,000	—	1,874,000
Adams	290,000	439,000	—	729,000
Bonney	174,000	205,000	—	379,000
Acevedo	—	—	—	—

ComEd

Name	Cash Payment ($) Note (1)	Value of Unvested Equity Awards ($) Note (2)	Value of ComEd Cash Based LTIP Awards ($) Note (3)	Perquisites and Other Benefits ($) Note (4)	Total Value of All Payments and Benefits ($) Note (5)
Clark	$589,000	$ —	$1,438,000	$ —	$2,027,000
Trpik	—	—	—	—	—
Pramaggiore	389,000	—	866,000	—	1,255,000
Donnelly	264,000	—	587,000	—	851,000
O'Neill	—	—	—	—	—

(1) Under the terms of the 2011 AIP, a pro−rated actual incentive award is payable upon retirement assuming an Individual Performance Multiplier (IPM) of 100% and based on the number of days worked during the year of retirement. Pursuant to Section 7.4(a) of his employment agreement, Mr. Rowe is entitled to a pro−rata portion of the lesser of his (i) actual annual incentive in the year of retirement (determined before the application of negative discretion by the board of directors) or (ii) Formula Annual Incentive, based on days worked during the year of retirement. His Formula Annual Incentive is defined as the greater of (i) the actual annual incentive paid for the latest calendar year ended on or before the termination, and (ii) the average annual incentive paid for the three years prior to the year of termination. Incentive calculations assume an IPM of 100% for the termination year.

(2) The Value of Unvested Equity Awards includes the sum of previously unvested stock options, previously earned but unvested performance share units, a pro−rated performance share unit award based on actual results for the year of termination due to retirement, and, if applicable (depending upon each officer's individual restricted stock or restricted stock unit awards (if any)), the value of any unvested restricted stock or restricted stock units that may vest upon retirement. For previously unvested stock options, the value is determined by taking the spread between the closing price of Exelon stock on December 30, 2011, which was $43.37 and the exercise price of each unvested stock option grant, multiplied by the number of unvested options. If an NEO has attained age 50 with 10 or more years of service (or deemed service), his or her unvested stock options will vest upon termination of employment because he or she has satisfied the definition of retirement under the LTIP. For all performance share units and restricted shares or restricted share units, the value is based on the December 30, 2011 closing price of Exelon stock.

(3) The value of cash based LTIP awards includes the value of earned and unvested award amounts and unearned award amounts. Pursuant to the ComEd LTIP, participants receive a pro−rated incentive award based on actual results for the year of termination, if termination occurs due to retirement.

(4) Represents the estimated value of (i) five years of office and secretarial services (at an assumed cost of $300,000/yr), which is to be provided pursuant to Section 7.7 of Mr. Rowe's employment agreement.

(5) The estimate of total payments and benefits is based on a December 31, 2011 retirement date.

Estimated Value of Benefits to be Received Upon Termination due to Death or Disability

The following tables show the estimated value of payments and other benefits to be conferred upon the NEOs assuming their employment is terminated due to death or disability as of December 31, 2011. These payments and benefits are in addition to the present value of the accumulated benefits from the NEO's qualified and non−qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Nonqualified Deferred Compensation section.

Exelon, Generation and PECO

Name	Cash Payment ($) Note (1)	Value of Unvested Equity Awards ($) Note (2)	Perquisites and Other Benefits ($)	Total Value of All Payments and Benefits ($) Note (4)
Rowe	$2,500,000	$5,540,000	$ —	$8,040,000
O'Brien	575,000	1,067,000	—	1,642,000
Hilzinger	402,000	768,000	—	1,170,000
Barnett	217,000	325,000	—	542,000
Pacilio	716,000	4,023,000	—	4,739,000
Crane	1,137,000	2,624,000	—	3,761,000
Von Hoene	616,000	1,630,000	—	2,246,000
Pardee	705,000	1,950,000	—	2,655,000
Adams	290,000	612,000	—	902,000
Bonney	174,000	344,000	—	518,000
Acevedo	102,000	181,000	—	283,000

Name	Cash Payment ($) Note (1)	Value of Unvested Equity Awards ($) Note (2)	Value of ComEd Cash Based LTIP Awards ($) Note (3)	Perquisites and Other Benefits ($)	Total Value of All Payments and Benefits ($) Note (4)
Clark	$589,000	$ —	$ 1,438,000	$ —	$2,027,000
Trpik	180,000	14,000	378,000	—	572,000
Pramaggiore	389,000	173,000	866,000	—	1,428,000
Donnelly	264,000	173,000	587,000	—	1,024,000
O'Neill	226,000	202,000	334,000	—	762,000

(1) Officers receive a pro−rated annual incentive award assuming an IPM of 100% and based on the number of days worked during the year of termination due to death or disability. Mr. Rowe would generally be entitled to a pro−rated portion of the lesser of his Formula Annual Incentive as specified by his employment agreement or the annual incentive for the year of termination (determined before application of negative discretion by the board of directors). Upon disability, Messrs. Pacilio, Crane, and Pardee would be eligible for an additional pension benefit of $4,267, $4,151, and $4,397, respectively, per month for the remainder of their lives commencing upon exhaustion of their LTD benefits.

(2) The Value of Unvested Equity Awards includes the sum of previously unvested stock options, previously earned but unvested performance share units, a pro−rated performance share unit award based on actual results for the year of termination due to death or disability, and, if applicable (depending upon each officer's individual restricted stock or restricted stock unit awards (if any)), the value of any unvested restricted stock or restricted stock units that may vest upon death or disability. For previously unvested stock options, the value is determined by taking the spread between the closing price of Exelon stock on December 30, 2011, which was $43.37, and the exercise price of each unvested stock option grant, multiplied by the number of unvested options. Under the terms of the LTIP, if an optionee terminates employment due to death or disability, all options vest upon termination. For all performance share units and restricted shares or restricted share units, the value is based on the December 30, 2011 closing price of Exelon stock.

(3) The value of cash based LTIP awards includes the value of earned and unvested award amounts and unearned award amounts. Pursuant to the ComEd LTIP, participants receive a pro−rated incentive award based on actual results for the year of termination, if termination occurs due to death or disability.

(4) The estimate of total payments and benefits is based on a December 31, 2011 termination date due to death or disability.

Estimated Value of Benefits to be Received Upon Involuntary Separation Not Related to a Change in Control

The following tables show the estimated value of payments and other benefits to be conferred upon the NEOs assuming they were terminated as of December 31, 2011 under the terms of the Amended and Restated Senior Management Severance Plan. These payments and benefits are in addition to the present value of the accumulated benefits from the NEO's qualified and non−qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in the tables within the Nonqualified Deferred Compensation section.

Exelon, Generation and PECO

Name	Cash Payment ($) Note (1)	Retirement Benefit Enhance−ment ($) Note (2)	Value of Unvested Equity Awards ($) Note (3)	Health and Welfare Benefit Continuation ($) Note (5)	Perquisites and Other Benefits ($) Note (6)	Total Value of All Payments and Benefits ($) Note (7)
Rowe	$2,500,000	$ —	$5,540,000	$ —	$1,500,000	$9,540,000
O'Brien	2,535,000	155,000	1,067,000	38,000	40,000	3,835,000
Hilzinger	1,585,000	86,000	699,000	26,000	40,000	2,436,000
Barnett	816,000	46,000	325,000	18,000	40,000	1,245,000
Pacilio	3,079,000	2,509,000	1,677,000	36,000	40,000	7,341,000
Crane	4,597,000	2,316,000	2,418,000	53,000	40,000	9,424,000
Von Hoene	2,804,000	164,000	1,561,000	39,000	40,000	4,608,000
Pardee	3,068,000	1,040,000	1,648,000	21,000	40,000	5,817,000
Adams	1,429,000	85,000	557,000	35,000	40,000	2,146,000
Bonney	736,000	322,000	205,000	17,000	40,000	1,320,000
Acevedo	483,000	28,000	96,000	16,000	40,000	663,000

ComEd

Name	Cash Payment ($) Note (1)	Retirement Benefit Enhance−ment ($) Note (2)	Value of Unvested Equity Awards ($) Note (3)	Value of ComEd Cash Based LTIP Awards ($) Note (4)	Health and Welfare Benefit Continuation ($) Note (5)	Perquisites and Other Benefits ($) Note (6)	Total Value of All Payments and Benefits ($) Note (7)
Clark	$2,654,000	$104,000	$ —	$1,438,000	$ 36,000	$ 40,000	$4,272,000
Trpik	724,000	39,000	14,000	378,000	13,000	40,000	1,208,000
Pramaggiore	1,874,000	105,000	150,000	866,000	35,000	40,000	3,070,000
Donnelly	963,000	50,000	150,000	587,000	21,000	40,000	1,811,000
O'Neill	864,000	45,000	183,000	334,000	20,000	40,000	1,486,000

(1) The cash payment to executives other than Mr. Rowe is composed of payment equal to a specified multiple of the NEO's base salary and annual incentive target, plus a pro−rated annual incentive award assuming an IPM of 100% and based on the number of days worked in the year of termination. Other than Mr. Rowe, the executives are participants in the Senior Management Severance Plan ("SMSP") and severance benefits are determined pursuant to Section 4 of the Severance Plan. Pursuant to Section 7.3(a) of his employment agreement, Mr. Rowe is entitled to a pro−rata portion of the lesser of his (i) actual annual incentive in the year of termination (determined before the application of negative discretion by the board of directors) or (ii) Formula Annual Incentive, based on days worked during the year of termination. Incentive calculations assume an IPM of 100% for the termination year. For all other officers except Messrs. Rowe, Hilzinger, Barnett, Bonney, Acevedo, Trpik, O'Neill, and Donnelly, the multiple used for base salary and annual incentive is 2. For Messrs. Barnett, Bonney, Acevedo, Trpik, O'Neill and Donnelly the multiple is 1.25 and for Mr. Hilzinger the multiple is 1.5.

(2) The retirement benefit enhancement consists of a one−time lump sum payment based on the actuarial present value of a benefit under the non−qualified pension plan assuming that the severance pay period was taken into account for purposes of vesting, and the severance pay constituted covered compensation for purposes of the non−qualified pension plan.

(3) The Value of Unvested Equity Awards includes the sum of previously unvested stock options, previously earned, but unvested performance share units, a pro−rated performance share unit award based on actual results for the year of termination, if termination occurs due to involuntary separation (other than for cause), and, if applicable (depending upon each officer's individual restricted stock or restricted stock unit awards (if any), the value of any unvested restricted stock that may vest upon involuntary separation not related to a change in control. For previously unvested stock options, the value is determined by taking the spread between the closing price of Exelon stock on December 30, 2011, which was $43.37, and the exercise price of each unvested stock option grant, multiplied by the number of unvested options. If an NEO has attained age 50 with 10 or more years of service (or certain deemed service), his or her unvested stock options will vest upon termination of employment because he or she has satisfied the definition of retirement under the LTIP. For all performance shares or restricted shares, the value is based on the December 30, 2011 closing price of Exelon stock.

(4) The value of cash based LTIP awards includes the value of earned and unvested award amounts and unearned award amounts. Pursuant to the ComEd LTIP, participants receive a pro−rated incentive award based on actual results for the year of termination, if termination occurs due to involuntary separation (other than for cause).
(5) Estimated costs of heath care, life insurance, and long−term disability coverage which continue during the severance period.
(6) Estimated costs of outplacement services for 12 months for all NEOs except Mr. Rowe. Pursuant to Section 7.7 of Mr. Rowe's employment agreement, he would receive five years of office and secretarial services (at an assumed cost of $300,000/yr).
(7) The estimate of total payments and benefits is based on a December 31, 2011 termination date.

Estimated Value of Benefits to be Received Upon a Qualifying Termination following a Change in Control

The following tables show the estimated value of payments and other benefits to be conferred upon the NEOs assuming they were terminated upon a qualifying change in control as of December 31, 2011. The company has entered into Change in Control agreements with Ms. Pramaggiore and Messrs. Clark, Crane, O'Brien, Pacilio, Pardee, and Von Hoene. These payments and benefits are in addition to the present value of accumulated benefits from the NEO's qualified and non−qualified pension plans shown in the tables within the Pension Benefit section and the aggregate balance due to each NEO that is shown in tables within the Nonqualified Deferred Compensation section. Mr. Rowe's employment agreement includes change in control provisions similar to those for the other NEOs. See Potential Payments upon Termination or Change in Control—Employment Agreement with Mr. Rowe for additional information.

Exelon, Generation and PECO

Name	Cash Payment ($) Note (1)	Retirement Benefit Enhance−ment ($) Note (2)	Value of Unvested Equity Awards ($) Note (3)	Health and Welfare Benefit Continuation ($) Note (5)	Perquisites and Other Benefits ($) Note (6)	Modified Gross−up Payment / Scaleback Note (7)	Total Value of All Payments and Benefits ($) Note (8)
Rowe	$2,500,000	$ —	$5,540,000	$ —	$1,500,000	Not Required	$ 9,540,000
O'Brien	3,760,000	156,000	1,067,000	57,000	40,000	Not Required	5,080,000
Hilzinger	2,031,000	114,000	768,000	34,000	40,000	Not Required	2,987,000
Barnett	1,271,000	74,000	325,000	29,000	40,000	Not Required	1,739,000
Pacilio	4,038,000	3,662,000	4,023,000	54,000	40,000	Not Required	11,817,000
Crane	6,161,000	3,125,000	2,624,000	80,000	40,000	Not Required	12,030,000
Von Hoene	3,973,000	245,000	1,630,000	58,000	40,000	Not Required	5,946,000
Pardee	4,038,000	1,516,000	1,950,000	31,000	40,000	Not Required	7,575,000
Adams	1,507,000	85,000	612,000	35,000	40,000	Not Required	2,279,000
Bonney	1,154,000	600,000	344,000	28,000	40,000	Not Required	2,166,000
Acevedo	738,000	45,000	181,000	25,000	40,000	Not Required	1,029,000

Name	Cash Payment ($) Note (1)	Retirement Benefit Enhance−ment ($) Note (2)	Value of Unvested Equity Awards ($) Note (3)	Value of ComEd Cash Based LTIP Awards ($) Note (4)	Health and Welfare Benefit Continuation ($) Note (5)	Perquisites and Other Benefits ($) Note (6)	Modified Gross−Up Payment / Scaleback Note (7)	Total Value of All Payments and Benefits ($) Note (8)
Clark	$3,555,000	$ 104,000	$ —	$ 1,438,000	$ 53,000	$ 40,000	Not Required	$5,190,000
Trpik	1,061,000	62,000	14,000	378,000	20,000	40,000	Not Required	1,575,000
Pramaggiore	2,545,000	158,000	173,000	866,000	52,000	40,000	Not Required	3,834,000
Donnelly	1,415,000	81,000	173,000	587,000	34,000	40,000	Not Required	2,330,000
O'Neill	1,246,000	71,000	202,000	334,000	32,000	40,000	Not Required	1,925,000

(1) Cash payment to executives other than Mr. Rowe includes a severance payment and the NEO's annual incentive for the year of termination assuming an IPM of 100%. With the exception of Messrs. Rowe, Hilzinger, Barnett, Adams, Bonney, Acevedo, Trpik, O'Neill, and Donnelly the severance benefit is equal to 2.99 times the sum of the executive's (i) current base salary and (ii) Severance Incentive. For Messrs. Hilzinger, Barnett, Adams, Bonney, Acevedo, Trpik, O'Neill, and Donnelly the severance benefit is equal to 2.0 times the sum of the executive's (i) current base salary and (ii) Severance Incentive. Cash payment also includes an additional payment for Mr. O'Brien of $35,000. The Severance Incentive is defined as the greater of the (i) target annual incentive for the year of termination and (ii) the average annual incentive paid for the two years prior to the year of termination (i.e., the 2009 and 2010 actual annual incentives).
Mr. Rowe is entitled to a pro−rata portion of the lesser of his (i) actual annual incentive in the year of termination (determined before the application of negative discretion by the board of directors) or (ii) Formula Annual Incentive, based on days worked during the year of termination. Mr. Rowe's Formula Annual Incentive is defined as the greater of the (i) the actual annual incentive paid for the latest calendar year ended on or before the termination date, and (ii) the average annual incentive paid for the three years prior to the year of termination (i.e., the 2008, 2009, and 2010 actual annual incentives). Incentive calculations assume an IPM of 100% for the termination year.

(2) Represents the estimated retirement benefit enhancement.

(3) The Value of Unvested Equity Awards includes the sum of previously unvested stock options, previously earned, but unvested performance share units, a pro−rated performance share unit award based on actual results for the year of termination due to a change in control, and, if applicable (depending upon each officer's individual restricted stock or restricted stock unit awards (if any)), the value of any unvested restricted stock that may vest upon a change in control. For previously unvested stock options, the value is determined by taking the spread between the closing price of Exelon stock on December 30, 2011, which was $43.37, and the exercise price of each unvested stock option grant, multiplied by the number of unvested options. If an NEO has attained age 50 with 10 or more years of service (or certain deemed service), his or her unvested stock options will vest upon termination of employment because he or she has satisfied the definition of retirement under the LTIP. For all performance shares or restricted shares, the value is based on the December 30, 2011 closing price of Exelon stock.

(4) The value of cash based LTIP awards includes the value of earned and unvested award amounts and unearned award amounts. Pursuant to the ComEd LTIP, participants receive a pro−rated incentive award based on actual results for the year of termination, if termination occurs due to a change in control.

(5) Health and welfare benefits (i.e., healthcare, life insurance and long−term disability) are continued during the severance period.

(6) Executives receive outplacement services for up to 12 months. Pursuant to Section 7.7 of Mr. Rowe's employment agreement Mr. Rowe would receive five years of office and secretarial services (at an assumed cost of $300,000/yr.).

(7) In 2009, the compensation committee adopted a policy that no future employment or severance agreements will provide for an excise tax gross−up payment. The SMSP as amended and restated on January 1, 2009 and CIC Employment Agreements that become effective after April 2, 2009 will reduce executives' parachute payments to his or her safe harbor in order to avoid the excise tax imposed under Section 4999 of the Internal Revenue Code. Messrs. O'Brien, Crane, Von Hoene Jr, Clark, and Pardee have grandfathered CIC Employment Agreements, which still entitle these NEOs to an excise tax gross−up payment only if the present value of their parachute payments exceed their safe harbor amount by more than 10%. If their parachute payments do not exceed the amount permitted by the IRS by more than 10%, their payments are reduced to their safe harbor.
Mr. Rowe's Employment Agreement was amended on October 27, 2009 to eliminate his excise tax gross−up protection and provide him with a "best after−tax" provision pursuant to which the Company will reduce his parachute payments to his safe harbor amount if his after−tax benefits would be higher following such a reduction of payments. If his after−tax benefits would be greater without a reduction of his parachute payments to his safe harbor amount, the Company will not reduce his payments and Mr. Rowe will be responsible for paying the excise tax imposed by Section 4999 of the Internal Revenue Code.
Amounts in this column represent the estimated value of the required excise tax gross−up payment or scaleback, if applicable.

(8) The estimate of total payments and benefits is based on a December 31, 2011 termination date.

Table of Contents

Non−Employee Director Compensation

Exelon

For their service as directors of the corporation, Exelon's non−employee directors receive the compensation shown in the following table and explained in the accompanying notes. One employee director, Mr. Rowe, not shown in the table, receives no additional compensation for service as a director.

	Committee Membership	Fees Earned or Paid in Cash: Annual Board & Committee Retainers	Fees Earned or Paid in Cash: Board & Committee Meeting Fees	Stock Awards	Change in Pension Value and Nonqualified Compensation Earnings (Note 1)	All Other Compensation (Note 2)	Total
John A. Canning, Jr.	A, C	$ 55,000	$ 58,000	$ 100,000	$ —	$ 5,000	$ 218,000
M. Walter D'Alessio	G (ch), C, L	85,000	54,000	100,000	—	—	239,000
Nicholas DeBenedictis	E (ch), G, P	65,000	64,000	100,000	—	—	229,000
Nelson A. Diaz	E, P, R	55,000	64,000	100,000	—	—	219,000
Sue L. Gin	R (ch), A, G, I	65,000	68,000	100,000	—	—	233,000
Rosemarie B. Greco	C (ch), E, G	60,000	64,000	100,000	—	—	224,000
Paul L. Joskow	A, E, I, R	55,000	68,000	100,000	—	—	223,000
Richard W. Mies	P (ch), A, R	80,000	68,000	100,000	—	—	248,000
John M. Palms (3)	A (ch), G, P, R	80,000	78,000	100,000	—	—	258,000
William C. Richardson (3)	A, C, G, I, R	55,000	86,000	100,000	—	5,000	246,000
Thomas J. Ridge	E, R	50,000	46,000	100,000	—	5,000	201,000
John W. Rogers, Jr.	I (ch), G, R	50,000	54,000	100,000	—	5,000	209,000
Stephen D. Steinour	A, C	55,000	56,000	100,000	—	5,000	216,000
Donald Thompson	E	50,000	30,000	100,000	—	—	180,000
Total All Directors		$860,000	$858,000	$1,400,000	$ —	$ 25,000	$3,143,000

Committee Membership Key

Audit = A, Chairman = Ch, Compensation = C, Corporate Governance = G, Energy Delivery Oversight = E, Risk Oversight− Investment Sub−Committee = I, Generation Oversight = P, Risk Oversight = R, Lead Director = L

Notes:

(1) Values in this column represent that portion of the directors accrued earnings in their non−qualified deferred compensation account that were considered as above market. See the description below under the heading "Deferred Compensation." For 2011, none of the directors recognized any such earnings.

(2) Values in this column represent the Company's matching portion of the director's contribution to qualified educational institutions pursuant to Exelon's matching Gift Plan described below in Other Compensation.

(3) In addition to the amounts shown in the table, Drs. Palms and Richardson, who also serve as directors of the Exelon Foundation, received $6,000 each from the Foundation for attending meetings of the Foundation's board. Exelon contributes to the Foundation to pay for the Foundation's operating expenses.

Table of Contents

Fees Earned or Paid in Cash

The Exelon board has a policy of targeting their compensation to the median board compensation of the same peer group of companies used to benchmark executive compensation. All directors receive an annual retainer of $50,000 paid in cash. The lead non−employee director received an annual retainer of $25,000. Committee chairmen receive an additional $10,000 retainer per year. In recognition of the additional time commitment and responsibility, members of the audit committee and generation oversight committee, including the committee chairs, receive an additional $5,000 per year for their participation on these committees, and the chairmen of these committees receive a $20,000 annual retainer.

Directors receive $2,000 for each meeting of the board, board committee or sub−committee that they attend, whether in person or by means of teleconferencing or video conferencing equipment. Directors also receive a $2,000 meeting fee for attending the annual shareholders meeting and the annual strategy retreat.

Stock Awards

Rather than paying directors entirely in cash, Exelon pays a significant portion of director compensation in the form of deferred stock units. The deferred stock units are not paid out to the directors until they retire from the board, leaving these amounts at risk during the director's entire tenure on the board. Directors are required under the Exelon Corporate Governance Principles to own 5,000 shares of Exelon common stock or deferred stock units within five years after their election to the board.

Directors receive deferred stock units worth $100,000 per year. Deferred stock units are granted and credited to a notional account maintained on the books of the corporation at the end of each calendar quarter based upon the closing price of Exelon common stock on the day the quarterly dividend is paid. Deferred stock units earn the same dividends available to all holders of Exelon common stock, which are reinvested in the account as additional units.

As of December 31, 2011, the directors held the following amounts of deferred Exelon common stock units. The units are valued at the closing price of Exelon common stock on December 30, 2011, which was $43.37. Legacy plans include those stock units earned from Exelon's predecessor companies, PECO Energy Company and Unicom Corporation. For Mr. Rogers, the legacy deferred stock units reflect accrued benefits from the Unicom 1996 Directors Fee Plan, which was terminated in 2000.

	Year First Elected to the Board	Deferred Stock Units From Legacy Plans #	Deferred Stock Units From Exelon Plan #	Total Deferred Stock Units #	Fair Market Value as of 12/31/11 $
John A. Canning	2008		8,099	8,099	$ 351,254
M. Walter D'Alessio	1983		17,352	17,352	752,556
Nicholas DeBenedictis	2002		14,792	14,792	641,529
Nelson A. Diaz	2004		14,656	14,656	635,631
Sue L. Gin	1993		8,857	8,857	384,128
Rosemarie B. Greco	1998		19,307	19,307	837,345
Paul L. Joskow	2007		9,408	9,408	408,025
Richard W. Mies	2009		7,052	7,052	305,845
John M. Palms	1990		14,792	14,792	641,529
William C. Richardson	2005		12,722	12,722	551,753
Thomas J. Ridge	2005		12,449	12,449	539,913
John W. Rogers, Jr	1999	3,962	22,864	26,826	1,163,444
Stephen D. Steinour	2007		9,705	9,705	420,906
Donald Thompson	2007		9,705	9,705	420,906
Total All Directors		3,962	181,760	185,722	$8,054,764

Deferred Compensation

Directors may elect to defer any portion their cash compensation in a non−qualified multi−fund deferred compensation plan. Each director has an unfunded account where the dollar balance can be invested in one or more of several mutual funds, including one fund composed entirely of Exelon common stock. Fund balances (including those amounts invested in the Exelon common stock fund) will be settled in cash and may be distributed in a lump sum or in annual installment payments upon a director’s reaching age 65, age 72 or upon retirement from the board. These funds are identical to those that are available to executive officers and are generally identical to those available to company employees who participate in the Exelon Employee Savings Plan. Directors and executive officers have one additional fund not available to employees that, through its composition, provides returns that can be in excess of 120% of the Federal long−term rate that is used by the IRS to determine above market returns. However, during 2011 none of the directors had investments in this fund.

Other Compensation

Exelon pays the cost of a director’s spouse’s travel, meals, lodging and related activities when the spouses are invited to attend company or industry related events where it is customary and expected that directors attend with their spouses. The cost of such travel, meals and other activities is imputed to the director as additional taxable income. However, in most cases there is no incremental cost to Exelon of providing transportation and lodging for a director’s spouse when he or she accompanies the director, and the only additional costs to Exelon are those for meals and activities and to reimburse the director for the taxes on the imputed income. In 2011, incremental cost to the company to provide these perquisites was less than $10,000 per director and the aggregate amount for all directors as a group, a total of 14 directors, was $21,466. The aggregate amount paid to all directors as a group (14 directors) for reimbursement of taxes on imputed income was $13,503.

Exelon has a board compensation and expense reimbursement policy under which directors are reimbursed for reasonable travel to and from their primary residence and lodging expenses incurred when attending board and committee meetings or other events on behalf of Exelon, (including director’s orientation or continuing education programs, facility visits or other business related activities for the benefit of Exelon). Under the policy, Exelon will arrange for its corporate aircraft to transport groups of directors, or when necessary, individual directors, to meetings in order to maximize the time available for meetings and discussion. Directors may bring their spouses on Exelon’s corporate aircraft when they are invited to an Exelon event, and the value of this travel, calculated according to IRS regulations, is imputed to the director as additional taxable income. Exelon has a matching gift program available to directors and officers that matches their contributions to educational institutions up to $5,000 per year and a matching gift program for other employees that matches their contributions to educational institutions up to $2,000 per year.

Generation

Generation does not have a board of directors.

Table of Contents

ComEd

For their service as directors of the company, ComEd's non−employee directors receive the compensation shown in the following table and explained in the accompanying notes. Mr. Clark and Mr. Rowe, not shown in the table, receive no additional compensation for their service as directors.

	Committee Membership	Fees Earned or Paid in Cash: Annual Board & Committee Retainers	Fees Earned or Paid in Cash: Board & Committee Meeting Fees	Change in Pension Value and Nonqualified Compensation Earnings Note 1	All Other Compensation Note 2	Total
James W. Compton	O	$ 70,000	$ 26,000	$ —	$ —	$ 96,000
A. Steven Crown (3)		45,192	10,000	—	—	55,192
Peter V. Fazio, Jr.	O	70,000	36,000	—	—	106,000
Sue L. Gin		—	16,000	—	—	16,000
Edgar D. Jannotta		70,000	6,000	—	5,000	81,000
Edward J. Mooney	O	70,000	22,000	—	—	92,000
Michael H. Moskow		70,000	10,000	—	—	80,000
Jesse H. Ruiz		70,000	14,000	—	—	84,000
Richard L. Thomas	O(Ch)	70,000	30,000	—	—	100,000
Total All Directors		$535,192	$170,000	$ —	$ 5,000	$710,192

Committee Membership Key: Operating = O; Chairman = Ch

(1) Values in this column represent that portion of the directors accrued earnings in their non−qualified deferred compensation account that were considered as above market. See the description below under the heading "Deferred Compensation." For 2011, none of the directors recognized any such earnings.
(2) Values in this column represent the Company's matching portion of the director's contribution to qualified educational institutions pursuant to Exelon's matching Gift Plan described below in Other Compensation.
(3) Mr. Crown was elected to the board on May 12, 2011.

Fees Earned or Paid in Cash

Non−employee directors of the ComEd board receive an annual retainer of $70,000 paid quarterly in arrears. Members of the ComEd board who are also members of the Exelon board do not receive this retainer. All non−employee directors receive $2,000 for each board or committee meeting attended whether in person or by means of teleconferencing or video conferencing equipment.

Deferred Compensation

Directors may elect to defer any portion their cash compensation in a non−qualified multi−fund deferred compensation plan. Each director has an unfunded account where the dollar balance can be invested in one or more of several mutual funds, including one fund composed entirely of Exelon common stock. Fund balances (including those amounts invested in the Exelon common stock fund) will be settled in cash and may be distributed in a lump sum or in annual installment payments upon a director's reaching age 65, age 72 or upon retirement from the board. These funds are identical to those that are available to executive officers and are generally identical to those available to company employees who participate in the Exelon Employee Savings Plan. Directors and executive officers have one additional fund not available to employees that, through its composition, provides returns that can be in excess of 120% of the Federal long−term rate that is used by the IRS to determine above market returns. However, during 2011 none of the directors had investments in this fund.

[Table of Contents](#)

The ComEd board does not grant any type of equity.

Other Compensation

ComEd pays the cost of a director's spouse's travel and meals when the spouses are invited to attend Exelon, ComEd or industry related events where it is customary and expected that directors attend with their spouses. The cost of such travel and meals is imputed to the director as additional taxable income. However, in most cases there is no incremental cost to ComEd of providing travel for a director's spouse when he or she accompanies the director, and the only additional costs to ComEd are those for meals and other minor expenses and to reimburse the director for the taxes on the imputed income. There were no such incremental costs during 2011 and no reimbursements for income taxes paid during 2011. Exelon has a matching gift program available to directors and officers that matches their contributions to educational institutions up to $5,000 per year and a matching gift program for other employees that matches their contributions to educational institutions up to $2,000 per year.

PECO

For their service as directors of the company, PECO's non−employee directors receive the compensation shown in the following table and explained in the accompanying notes. Two employee directors, Mr. O'Brien and Mr. Rowe, not shown in the table, receive no additional compensation for their service as directors.

In July 2008, the PECO board voted to reduce its size to seven members. At the same time it also established an Executive Committee to assist the board in its management and oversight duties and to act on behalf of the board when the full board was not in session. Mr. O'Brien, Mr. Rowe, and Mr. D'Alessio were appointed to this committee.

		Fees Earned or Paid in Cash				
	Committee Membership	Annual Board & Committee Retainers	Board & Committee Meeting Fees	Change in Pension Value and Nonqualified Compensation Earnings (Note 1)	All Other Compensation (Note 2)	Total
M. Walter D'Alessio	E	$ —	$ 6,000	$ —	$ —	$ 6,000
Nelson A. Diaz		—	6,000	—	—	6,000
Rosemarie B. Greco		—	6,000	—	—	6,000
Charisse R. Lillie		70,000	6,000	—	—	76,000
Thomas J. Ridge		—	6,000	—	—	6,000
Ronald Rubin		70,000	6,000	—	—	76,000
Total All Directors		$140,000	$ 36,000	$ —	$ —	$176,000

Committee Membership Key

E = Executive Committee

(1) Values in this column represent that portion of the directors accrued earnings in their non−qualified deferred compensation account that were considered as above market. See the description below under the heading "Deferred Compensation." For 2011, none of the directors recognized any such earnings.

(2) Values in this column represent the Company's matching portion of the director's contribution to qualified educational institutions pursuant to Exelon's matching Gift Plan described below in Other Compensation. Mr. Ridge made such a contribution during 2011, and the company matching portion is included in the Exelon Non−employee Compensation Table.

Fees Earned or Paid in Cash

Non−employee members of the PECO board receive an annual retainer of $70,000 paid quarterly in arrears. Members of the PECO board who are also members of the Exelon board do not receive this retainer. Non−employee directors receive $2,000 for each board or committee meeting attended whether in person or by means of teleconferencing or video conferencing equipment.

Deferred Compensation

Directors may elect to defer any portion their cash compensation in a non−qualified multi−fund deferred compensation plan. Each director has an unfunded account where the dollar balance can be invested in one or more of several mutual funds, including one fund composed entirely of Exelon common stock. Fund balances (including those amounts invested in the Exelon common stock fund) will be settled in cash and may be distributed in a lump sum or in annual installment payments upon a director’s reaching age 65, age 72 or upon retirement from the board. These funds are identical to those that are available to executive officers and are generally identical to those available to company employees who participate in the Exelon Employee Savings Plan. Directors and executive officers have one additional fund not available to employees that, through its composition, provides returns that can be in excess of 120% of the Federal long−term rate that is used by the IRS to determine above market returns. However, during 2011 none of the directors had investments in this fund.

The PECO board does not grant any type of equity.

Other Compensation

PECO pays the cost of a director’s spouse’s travel and meals when the spouses are invited to attend Exelon, PECO or industry related events where it is customary and expected that directors attend with their spouses. The cost of such travel and meals is imputed to the director as additional taxable income. However, in most cases there is no incremental cost to PECO of providing travel for a director’s spouse when he or she accompanies the director, and the only additional costs to PECO are those for meals and other minor expenses and to reimburse the director for the taxes on the imputed income. There were no such incremental costs during 2011 and no reimbursements for income taxes paid during 2011. Exelon has a matching gift program available to directors and officers that matches their contributions to educational institutions up to $5,000 per year and a matching gift program for other employees that matches their contributions to educational institutions up to $2,000 per year.

Table of Contents

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Exelon, Generation and PECO

The following table shows the ownership of Exelon common stock as of December 31, 2011 by any person or entity that has publicly disclosed ownership of more than five percent of Exelon's outstanding stock, each director, each named executive officer in the Summary Compensation Table, and for all directors and executive officers as a group.

	[A] Beneficially Owned Shares	[B] Shares Held in Company Plans (Note 1)	[C] Vested Stock Options and Options that Vest Within 60 days	[D]=[A]+[B]+[C] Total Shares Held	[E] Share Equivalents to be Settled in Cash or Stock (Note 2)	[F]=[D]+[E] Total Share Interest
Directors						
John A. Canning, Jr.	5,000	8,099	—	13,099	967	14,066
M. Walter D'Alessio (3)	13,647	17,352	—	30,999	—	30,999
Nicholas DeBenedictis	—	14,792	—	14,792	—	14,792
Nelson A. Diaz (3)	1,500	14,656	—	16,156	4,135	20,291
Sue L. Gin	50,736	8,857	—	59,593	11,673	71,266
Rosemarie B. Greco (3)	2,000	19,307	—	21,307	5,328	26,635
Paul L. Joskow	2,000	9,408	—	11,408	5,275	16,683
Charisse R. Lillie (4)	—	—	—	—	—	—
Richard W. Mies	—	7,052	—	7,052	—	7,052
John M. Palms	—	14,792	—	14,792	—	14,792
William C. Richardson	1,487	12,722	—	14,209	—	14,209
Thomas J. Ridge (3)	—	12,449	—	12,449	8,854	21,303
John W. Rogers, Jr.	11,374	26,826	—	38,200	12,024	50,224
Ronald Rubin (4)	4,748	—	—	4,748	326	5,074
Stephen D. Steinour	4,520	9,705	—	14,225	11,038	25,263
Donald Thompson	—	9,705	—	9,705	8,073	17,778
Named Officers						
John W. Rowe	301,915	7,111	744,500	1,053,526	28,091	1,081,617
Denis P. O'Brien	27,044	7,240	198,775	233,059	8,163	241,222
Matthew F. Hilzinger	17,815	5,627	74,825	98,267	3,034	101,301
Phillip S. Barnett	11,741	—	50,150	61,891	2,275	64,166
Michael J. Pacilio	8,883	70,000	40,875	119,758	2,825	122,583
Christopher M. Crane	44,146	15,000	203,750	262,896	10,065	272,961
William A. Von Hoene, Jr.	24,747	5,000	125,650	155,397	5,848	161,245
Charles G. Pardee	17,551	18,000	111,600	147,151	5,420	152,571
Craig L. Adams	7,483	—	54,000	61,483	1,652	63,135
Paul R. Bonney	15,530	1,141	41,325	57,996	1,153	59,149
Jorge Acevedo	4,339	912	14,700	19,951	315	20,266
Total						
Directors & Executive Officers as a group, 35 people. (See Note 5)	659,352	404,214	2,009,052	3,072,618	149,794	3,222,412

(1) The shares listed under Shares Held in Company Plans, Column [B], include restricted shares, shares held in the 401(k) plan, and deferred shares held in the Stock Deferral Plan.

(2) The shares listed above under Share Equivalents to be Settled in Cash, Column [E], include unvested performance shares that may settled in cash or stock depending on where the named officer stands with respect to their stock ownership requirement, and phantom shares held in a non−qualified deferred compensation plan which will be settled in cash on a 1 for 1 basis upon retirement or termination.
(3) Messrs. D'Alessio, Diaz and Ridge, and Ms. Greco, are directors of Exelon and PECO.
(4) Ms. Lillie and Mr. Rubin are directors of PECO.
(5) Beneficial ownership, shown in Column [A], of directors and executive officers as a group represents less than 1% of the outstanding shares of Exelon common stock. Total includes share holdings from all directors and NEOs as well as those executive officers listed in Item 1, Executive Officers of the Registrants, who are not NEOs for purposes of compensation disclosure.

Other significant owners of Exelon stock

Shown in the table below are those owners who are known to Exelon to hold more than 5% of the outstanding common stock. This information is based on the most recent Schedule 13Gs filed with the SEC by BlackRock, Inc. on February 2, 2011 and by State Street on February 9, 2012.

Name and address of beneficial owner	Amount and nature of beneficial ownership	Percent of class
BlackRock, Inc. 40 East 52nd Street New York, NY 10022	35,569,861	5%
State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	33,565,728	5%

BlackRock, Inc. disclosed in its Schedule 13G that it has sole power to vote or to direct the vote and sole power to dispose or direct the disposition of 35,569,861 shares. State Street Corporation disclosed in its Schedule 13G that it has shared voting and dispositive power over 33,565,728 shares.

Stock Ownership Requirements for Directors and Officers

Under Exelon's Corporate Governance Principles, all directors are required to own within five years after election to the board at least 5,000 shares of Exelon common stock or deferred stock units or shares accrued in the Exelon common stock fund of the directors' deferred compensation plan. The corporate governance committee utilized an independent compensation consultant who determined that, compared to its peer group, Exelon's ownership requirement is reasonable.

Table of Contents

Officers of Exelon (and its subsidiaries other than ComEd) are required to own certain amounts of Exelon common stock, depending on their seniority, by the later of five years after their employment or promotion to their current position. The objective is to encourage officers to think and act like owners. The ownership guidelines are expressed as both a fixed number of shares and a multiple of annualized base salary to avoid arbitrary changes to the ownership requirements that could arise from ordinary course volatility in the market price for Exelon's shares. The minimum stock ownership targets by level are the lesser of the fixed number of shares or the multiple of annualized base salary. The number of shares was determined by taking the following multiples of the officer's base salary as of the latest of September 30, 2011 or the date of hire or promotion: (1) Chairman and CEO, five times base salary; (2) executive vice presidents, three times base salary; (3) presidents and senior vice presidents, two times base salary; and (4) vice presidents and other executives, one times base salary. Ownership is measured by valuing an executive's holdings using the 60−day average price of Exelon common stock as of the appropriate date. Shares held outright, earned non−vested performance shares, and deferred shares count toward the ownership guidelines; unvested restricted stock and stock options do not count for this purpose. As of January 24, 2012, the named executive officers (NEOs) held the following amounts of stock relative to the applicable guidelines:

Name	Ownership Multiple	Ownership Guideline in Shares	Share or Share Equivalents Owned	Ownership As a Percent of Guideline
John W. Rowe	5x	107,920	419,283	389%
Denis P. O'Brien	3x	17,494	56,597	324%
Matthew F. Hilzinger	2x	10,000	29,692	297%
Phillip S. Barnett	2x	10,000	18,710	187%
Michael J. Pacilio	2x	10,000	30,147	301%
Christopher M. Crane	3x	21,868	82,012	375%
William A. Von Hoene, Jr.	3x	17,429	52,013	298%
Charles G. Pardee	2x	12,950	41,847	323%
Craig L. Adams	2x	10,000	16,200	162%
Paul R. Bonney	1x	4,000	23,294	582%
Jorge Acevedo	1x	4,000	8,522	213%

Securities Authorized for Issuance under Exelon Equity Compensation Plans

[A] Plan Category	[B] Number of securities to be issued upon exercise of outstanding options (Note 1)	[C] Weighted−average price of outstanding options	[D] Number of securities remaining available for future issuance under equity compensation plans (Note 2)
Equity compensation plans approved by security holders	13,449,422	$ 48.47	24,302,890

(1) Includes stock options, unvested performance shares, unvested restricted shares that were granted under the Exelon LTIP or predecessor company plans and shares awarded under those plans and deferred into the stock deferral plan, as well as deferred stock units granted to directors as part of their compensation plan described in Item 11, Executive Compensation—Non−employee Director Compensation. See Note 16 of the Combined Notes to Consolidated Financial Statements for additional information.
(2) Excludes securities to be issued upon exercise of outstanding options and vesting of shares or deferred stock units shown in column [B].

No Generation securities are authorized for issuance under equity compensation plans, and no PECO securities are authorized for issuance under equity compensation plans.

Table of Contents

ComEd

Exelon Corporation indirectly owns 127,002,904 shares of ComEd common stock, more than 99% of all outstanding shares. Accordingly, the only beneficial holder of more than five percent of ComEd's voting securities is Exelon, and none of the directors or executive officers of ComEd hold any ComEd voting securities.

The following table shows the ownership of Exelon common stock as of December 31, 2011 by (1) any director of ComEd, (2) each named executive officer of ComEd named in the Summary Compensation Table, and (3) all directors and executive officers of ComEd as a group.

No ComEd securities are authorized for issuance under equity compensation plans. For information about Exelon securities authorized for issuance to ComEd employees under Exelon equity compensation plans, see above under "Exelon−Securities Authorized Under Equity Compensation Plans."

	[A]	[B]	[C]	[D]=[A]+[B]+[C]	[E]	[F]=[D]+[E]
	Beneficially Owned Shares	Shares Held in Company Plans (Note 1)	Vested Stock Options and Options that Vest Within 60 days	Total Shares Held	Share Equivalents to be Settled in Cash or Stock (Note 2)	Total Share Interest
Directors						
James W. Compton	6,000	—	—	6,000	—	6,000
A. Steven Crown	—	—	—	—	1,298	1,298
Peter V. Fazio, Jr.	1,000	—	—	1,000	—	1,000
Sue L. Gin	50,736	8,857	—	59,593	11,673	71,266
Edgar D. Jannotta	26,282	—	—	26,282	—	26,282
Edward J. Mooney	—	—	—	—	—	—
Michael H. Moskow	—	—	—	—	—	—
John W. Rowe	301,915	7,111	744,500	1,053,526	28,091	1,081,617
Jess H. Ruiz	—	—	—	—	—	—
Richard L. Thomas	33,369	—	—	33,369	—	33,369
Named Officers						
Frank M. Clark	24,935	—	66,000	90,935	6,081	97,016
Joseph R. Trpik, Jr.	4,874	592	17,725	23,191	514	23,705
Anne R. Pramaggiore	11,773	4,000	26,850	42,623	—	42,623
Terence R. Donnelly	19,484	5,248	51,800	76,532	1,005	77,537
Thomas S. O'Neill	9,636	5,894	50,325	65,855	2,733	68,588
Total						
Directors & Executive Officers as a group, 19 people	504,947	32,614	994,450	1,532,011	52,342	1,584,353

(1) The shares listed under Shares Held in Company Plans, Column [B], include restricted shares, shares held in the 401(k) plan, and deferred shares held in the Stock Deferral Plan.

(2) The shares listed above under Share Equivalents to be Settled in Cash, Column [E], include unvested performance shares that may settled in cash or stock depending on where the named officer stands with respect to their stock ownership requirement, and phantom shares held in a non−qualified deferred compensation plan which will be settled in cash on a 1 for 1 basis upon retirement or termination.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

Exelon

The information required by Item 13 relating to transactions with related persons and director independence is incorporated herein by reference to information to be filed in the 2012 Exelon Proxy Statement.

Generation

There were no related person transactions involving Generation. Generation does not have a board of directors.

ComEd

Sidley Austin LLP provided legal services to Exelon and ComEd during 2011. The spouse of Mr. Ruiz, a member of the ComEd board of directors, is a partner of Sidley Austin LLP.

The ComEd board of directors has adopted the independence standards of The New York Stock Exchange as its independence standards. In assessing the independence of its directors, the ComEd board considered the relationships of its directors with Exelon as well as the business and charitable relationships among Exelon, ComEd and businesses and charities with which its directors are affiliated. With respect to Mr. Ruiz, the ComEd board considered the relationship of his spouse with a law firm that provides legal services to Exelon and ComEd, as disclosed above. The board determined that none of the relationships was material and accordingly that Messrs. Compton, Ruiz, Mooney, Fazio and Moskow are independent. Messrs. Rowe, Clark, Jannotta, and Thomas and Ms. Gin are all current or former officers or directors of Exelon and, accordingly, are not independent.

PECO

There were no related person transactions involving PECO. Under PECO’s bylaws, an “independent director” is a director who is not a director, officer or employee of Exelon, PECO or any other Exelon Corporation affiliate (excluding for this purpose positions as directors of PECO or subsidiaries of PECO). Messrs. Rowe, D’Alessio, Diaz, O’Brien and Ridge and Ms. Greco are all current officers or directors of Exelon or PECO and, accordingly, are not independent.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Exelon

In July 2002, the Exelon Audit Committee (Committee) adopted a policy for pre−approval of services to be performed by the independent accountants. The Committee pre−approves annual budgets for audit, audit−related and tax compliance and planning services. The services that the Committee will consider include services that do not impair the accountant's independence and add value to the audit, including audit services such as attest services and scope changes in the audit of the financial statements, audit−related services such as accounting advisory services related to proposed transactions and new accounting pronouncements, the issuance of comfort letters and consents in relation to financings, the provision of attest services in relation to regulatory filings and contractual obligations, and tax compliance and planning services. With respect to non−budgeted services in amounts less than $500,000, the Committee delegated authority to the Committee's chairman to pre−approve such services. All other services must be pre−approved by the Committee. The Committee receives quarterly reports on all fees paid to the independent accountants. None of the services provided by the independent accountants was provided pursuant to the de minimis exception to the pre−approval requirements contained in the SEC's rules.

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of Exelon's annual financial statements for the years ended December 31, 2011 and 2010, and fees billed for other services rendered by PricewaterhouseCoopers LLP during those periods. Fees include amounts related to the year indicated, which may differ from amounts billed.

(in thousands)	Year Ended December 31, 2011	Year Ended December 31, 2010
Audit fees	$9,807	$9,152
Audit related fees [(a)]	3,933	851
Tax fees [(b)]	738	472
All other fees [(c)]	185	21

(a) Audit related fees consist of assurance and related services that are traditionally performed by the auditor. This category includes fees for accounting assistance, purchase accounting reviews, procedures associated with S−4 filings, due diligence in connection with proposed acquisitions or sales, merger integration services and consultations concerning financial accounting and reporting standards.

(b) Tax fees consist of the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP for tax compliance, tax advice, and tax planning. These services included tax compliance and preparation services, including the preparation of original and amended tax returns, claims for refunds, and tax payment planning, and tax advice and consulting services, including assistance and representation in connection with tax audits and appeals, tax advice related to proposed acquisitions or sales, employee benefit plans and requests for rulings or technical advice from taxing authorities.

(c) All other fees reflect work performed primarily in connection with research, audit software licenses and assessment of merger integration activities.

Generation, ComEd and PECO

Generation, ComEd and PECO are indirect controlled subsidiaries of Exelon. The audit committee function is fulfilled for Generation, ComEd and PECO by the Committee. See ITEM 10. Directors, Executive Officers of the Registrant and Corporate Governance for additional information regarding the Committee. See discussion under "Exelon" above for a description of the Committee's policy and process for approving services to be performed by the independent accountants on behalf of Exelon, Generation, ComEd and PECO. None of the services provided by the independent accountants was provided pursuant to the de minimis exception to the pre−approval requirements contained in the SEC's rules.

Table of Contents

The following tables present fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of Generation's, ComEd's and PECO's annual financial statements for the years ended December 31, 2011 and 2010, and fees billed for other services rendered by PricewaterhouseCoopers LLP during those periods. These fees include an allocation of amounts billed directly to Exelon Corporation. Fees include amounts related to the year indicated, which may differ from amounts billed.

Generation

(in thousands)	Year Ended December 31, 2011	Year Ended December 31, 2010
Audit fees	$3,693	$3,994
Audit related fees (a)	612	615
Tax fees (b)	385	325
All other fees (c)	82	9

(a) Audit−related fees consist of assurance and related services that are traditionally performed by the auditor. This category includes fees for purchase accounting reviews, due diligence in connection with proposed acquisitions or sales and merger integration services.
(b) Tax fees consist of the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP for tax compliance, tax advice, tax planning and tax advice related to proposed acquisitions or sales,
(c) All other fees reflect work performed primarily in connection with research, audit software licenses and assessment of merger integration activities.

ComEd

(in thousands)	Year Ended December 31, 2011	Year Ended December 31, 2010
Audit fees	$2,180	$2,639
Audit related fees (a)	328	142
Tax fees (b)	187	66
All other fees (c)	54	6

(a) Audit related fees consist of assurance and related services that are traditionally performed by the auditor. This category includes fees for regulatory work and merger integration services.
(b) Tax fees consist of the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP for tax compliance, tax advice, and tax planning.
(c) All other fees reflect work performed primarily in connection with research, audit software licenses and assessment of merger integration activities.

PECO

(in thousands)	Year Ended December 31, 2011	Year Ended December 31, 2010
Audit fees	$1,870	$1,590
Audit related fees (a)	248	66
Tax fees (b)	98	68
All other fees (c)	29	4

(a) Audit related fees consist of assurance and related services that are traditionally performed by the auditor. This category includes fees for regulatory work and merger integration services.
(b) Tax fees consist of the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP for tax compliance, tax advice, tax planning and tax advice and consulting services in connection with appeals claims.
(c) All other fees reflect work performed primarily in connection with research, audit software licenses and assessment of merger integration activities.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report:

Exelon

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2012 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Balance Sheets at December 31, 2011 and 2010

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2011, 2010 and 2009

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule I – Condensed Financial Information of Parent (Exelon Corporate) at December 31, 2011 and 2010 and for the Years Ended December 31, 2011, 2010 and 2009

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto.

Table of Contents

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Operations

(In millions)	For the Years Ended December 31, 2011	2010	2009
Operating expenses			
Operating and maintenance	$ 56	$ 13	$ 45
Operating and maintenance from affiliates	44	22	35
Other	4	2	—
Total operating expenses	104	37	80
Operating loss	(104)	(37)	(80)
Other income and deductions			
Interest expense, net	(75)	(90)	(133)
Equity in earnings of investments	2,662	2,652	2,835
Interest income from affiliates, net	1	—	—
Other, net	8	6	(42)
Total other income and deductions	2,596	2,568	2,660
Income before income taxes	2,492	2,531	2,580
Income taxes	(3)	(32)	(127)
Net income	$2,495	$2,563	$2,707

See Notes to Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies

Schedule I – Condensed Financial Information of Parent (Exelon Corporate)

Condensed Statements of Cash Flows

(In millions)	For the Years Ended December 31, 2011	2010	2009
Net cash flows provided by operating activities	$ 766	$ 2,014	$ 2,767
Cash flows from investing activities			
Changes in Exelon intercompany money pool	20	(5)	31
Capital expenditures	(28)	(7)	—
Return on capital from equity method investee	(1)	92	—
Investment in affiliates	(65)	(290)	(454)
Net cash flows used in investing activities	(74)	(210)	(423)
Cash flows from financing activities			
Changes in short−term debt	161	—	(56)
Retirement of long−term debt	—	(400)	(500)
Dividends paid on common stock	(1,393)	(1,389)	(1,385)
Proceeds from employee stock plans	38	48	42
Other financing activities	(1)	5	7
Net cash flows used in financing activities	(1,195)	(1,736)	(1,892)
Increase (decrease) in cash and cash equivalents	(503)	68	452
Cash and cash equivalents at beginning of period	541	473	21
Cash and cash equivalents at end of period	$ 38	$ 541	$ 473

See Notes to Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
ASSETS		
Current assets		
Cash and cash equivalents	$ 38	$ 541
Accounts receivable, net		
Other accounts receivable	111	132
Accounts receivable from affiliates	9	8
Deferred income taxes	22	—
Notes receivable from affiliates	—	322
Other	3	—
Total current assets	183	1,003
Property, plant and equipment, net	32	6
Deferred debits and other assets		
Regulatory assets	2,991	2,750
Investments in affiliates	18,951	16,974
Deferred income taxes	2,058	1,955
Other	24	21
Total deferred debits and other assets	24,024	21,700
Total assets	$24,239	$22,709

See Notes to Financial Statements

Table of Contents

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Condensed Balance Sheets

(In millions)	December 31, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short−term borrowings	$ 161	$ —
Payables to affiliates	30	—
Accrued expenses	117	64
Other	403	345
Total current liabilities	711	409
Long−term debt	1,313	1,313
Deferred credits and other liabilities		
Pension obligations	6,797	6,434
Non−pension postretirement benefit obligations	965	928
Other	68	65
Total deferred credits and other liabilities	7,830	7,427
Total liabilities	9,854	9,149
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 663 and 662 shares outstanding at December 31, 2011 and 2010, respectively)	9,107	9,006
Treasury stock, at cost (35 shares held at December 31, 2011 and 2010, respectively)	(2,327)	(2,327)
Retained earnings	10,055	9,304
Accumulated other comprehensive loss, net	(2,450)	(2,423)
Total shareholders' equity	14,385	13,560
Total liabilities and shareholders' equity	$24,239	$22,709

See Notes to Financial Statements

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

1. Basis of Presentation

Exelon Corporate is a holding company that conducts substantially all of its business operations through its subsidiaries. These condensed financial statements and related footnotes have been prepared in accordance with Rule 12−04, Schedule I of Regulation S−X. These statements should be read in conjunction with the consolidated financial statements and notes thereto of Exelon Corporation.

Exelon Corporate owns 100% of all of its significant subsidiaries, either directly or indirectly, except for Commonwealth Edison Company (ComEd), of which Exelon Corporate owns more than 99%, and PECO Energy Company (PECO), of which Exelon Corporate owns 100% of the common stock but none of PECO's preferred securities.

2. Debt and Credit Agreements

Short−Term Borrowings

Exelon Corporate meets its short−term liquidity requirements primarily through the issuance of commercial paper. Exelon Corporate had commercial paper borrowings of $161 million and $0 million at December 31, 2011 and 2010, respectively.

Credit Agreements

As of December 31, 2011, Exelon Corporate had access to an unsecured credit facility with aggregate bank commitments of $500 million and available capacity under those commitments of $493 million. The credit facility expires on March 23, 2016. See Note 10 of the Combined Notes to Consolidated Financial Statements for further information regarding Exelon Corporate's credit agreement.

Long−Term Debt

Exelon Corporate will not have any long−term debt maturities in periods 2012 through 2014. The debt maturities for the periods 2015, 2016 and thereafter are as follows:

2015	$ 800
2016	—
Remaining years	500
Total long−term debt	1,300
Unamortized debt discount and premium, net	(1)
Fair value hedge carrying value adjustment, net	14
Long−term debt	$1,313

3. Commitments and Contingencies

See Note 18 of the Combined Notes to Consolidated Financial Statements for Exelon Corporate's commitments and contingencies related to environmental matters, savings plan claim and fund transfer restrictions.

Table of Contents

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

4. Related Party Transactions

The financial statements of Exelon Corporate include related party transactions as presented in the tables below:

	For the Years Ended December 31, 2011	2010	2009
Operating and maintenance from affiliates:			
Business Services Company, LLC [a]	$ 44	$ 22	$ 35
Interest income from affiliates, net	$ 1	$ —	$ —
Equity in earnings of investments:			
Exelon Energy Delivery Company, LLC [b]	$ 801	$ 657	$ 723
Exelon Ventures Company, LLC [c]	1,769	1,978	2,113
UII, LLC	18	23	1
Exelon Transmission Company, LLC	(3)	(6)	(2)
Exelon Consolidations [d]	77	—	—
Total equity in earnings of investments	$2,662	$ 2,652	$ 2,835
Charitable contributions to Exelon Foundation [e]	$ —	$ 10	$ 10
Cash contributions received from affiliates	$ 820	$ 2,056	$ 2,841

	December 31, 2011	2010
Accounts receivable from affiliates (current):		
Business Services Company, LLC [a]	$ —	$ 1
Generation	7	5
ComEd	1	1
PECO	1	1
Total accounts receivables from affiliates (current)	$ 9	$ 8
Notes receivable from affiliate (current): [a]		
Business Services Company, LLC	$ —	$ 20
ComEd	—	302
Total notes receivables from affiliates (current)	$ —	$ 322
Investments in affiliates:		
Business Services Company, LLC [a]	$ 160	$ 159
Exelon Energy Delivery Company, LLC [b]	10,040	9,788
Exelon Ventures Company, LLC [c]	8,310	6,601
UII, LLC	447	429
Exelon Transmission Company, LLC	6	3
VEBA	(12)	(6)
Total investments in affiliates	$18,951	$16,974
Payables to affiliate (current)		
Exelon Consolidations	$ 27	$ —
Business Services Company, LLC [a]	3	—
Total payables to affiliate (current)	$ 30	$ —

Exelon Corporation and Subsidiary Companies
Schedule I – Condensed Financial Information of Parent (Exelon Corporate)
Notes to Financial Statements

(a) Exelon Corporate receives a variety of corporate support services from BSC, including legal, human resources, financial, information technology and supply management services. All services are provided at cost, including applicable overhead.
(b) Exelon Energy Delivery Company, LLC consists of ComEd and PECO.
(c) Exelon Ventures Company, LLC primarily consists of Generation.
(d) Equity in earnings of investments for Exelon Consolidations represents the intercompany income component that offsets the corresponding intercompany expense at Generation for upgrades in transmission assets owned by ComEd, which are reflected as assets at Exelon Corporate.
(e) Exelon Foundation is a nonconsolidated not−for−profit Illinois corporation. The Exelon Foundation was established in the fourth quarter of 2007 to serve educational and environmental philanthropic purposes and does not serve a direct business or political purpose of Exelon. Exelon contributes services (i.e. accounting, administrative, legal).

Table of Contents

Exelon Corporation and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 228	$ 121	$ 16[(a)]	$ 157[(b)]	$ 208
Deferred tax valuation allowance	9	1	—	—	10
Reserve for obsolete materials	56	6	—	2	60
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 225	$ 109	$ 25[(a)]	$ 131[(b)]	$ 228
Deferred tax valuation allowance	36	(8)	—	19	9
Reserve for obsolete materials	45	12	—	1	56
For The Year Ended December 31, 2009					
Allowance for uncollectible accounts	$ 238	$ 150	$ 38[(a)]	$ 201[(b)]	$ 225
Deferred tax valuation allowance	29	9	—	2	36
Reserve for obsolete materials	28	19	—	2	45

(a) Primarily charges for late payments and non−service receivables.
(b) Write−off of individual accounts receivable.

Table of Contents

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Generation

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2012 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Balance Sheets at December 31, 2011 and 2010

   Consolidated Statements of Changes in Member's Equity for the Years Ended December 31, 2011, 2010 and 2009

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Exelon Generation Company, LLC and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 32	$ —	$ —	$ 3	$ 29
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	55	4	—	—	59
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 31	$ 1	$ —	$ —	$ 32
Deferred tax valuation allowance	18	—	—	18	—
Reserve for obsolete materials	43	12	—	—	55
For The Year Ended December 31, 2009					
Allowance for uncollectible accounts	$ 30	$ 2	$ —	$ 1	$ 31
Deferred tax valuation allowance	20	—	—	2	18
Reserve for obsolete materials	26	17	—	—	43

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

ComEd

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2012 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Balance Sheets at December 31, 2011 and 2010

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2011, 2010 and 2009

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

Table of Contents

Commonwealth Edison Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 80	$ 57	$ 15[(a)]	$ 74[(b)]	$ 78
Reserve for obsolete materials	1	2	—	2	1
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 77	$ 48	$ 16[(a)]	$ 61[(b)]	$ 80
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2009					
Allowance for uncollectible accounts	$ 57	$ 85	$ 27[(a)]	$ 92[(b)]	$ 77
Reserve for obsolete materials	1	2	—	2	1

(a) Primarily charges for late payments and non−service receivables.
(b) Write−off of individual accounts receivable.

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

PECO

1. Financial Statements:

   Report of Independent Registered Public Accounting Firm dated February 9, 2012 of PricewaterhouseCoopers LLP

   Consolidated Statements of Operations and Comprehensive Income for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

   Consolidated Balance Sheets at December 31, 2011 and 2010

   Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2011, 2010 and 2009

   Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

   Schedule II – Valuation and Qualifying Accounts

   Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements, including the notes thereto

PECO Energy Company and Subsidiary Companies
Schedule II – Valuation and Qualifying Accounts

Column A	Column B	Column C		Column D	Column E
		Additions and adjustments			
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
			(in millions)		
For The Year Ended December 31, 2011					
Allowance for uncollectible accounts	$ 116	$ 64	$ 1[(a)]	$ 80[(b)]	$ 101
Deferred tax valuation allowance	—	—	—	—	—
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2010					
Allowance for uncollectible accounts	$ 117	$ 60	$ 9[(a)]	$ 70[(b)]	$ 116
Deferred tax valuation allowance	1	—	—	1	—
Reserve for obsolete materials	1	—	—	—	1
For The Year Ended December 31, 2009					
Allowance for uncollectible accounts	$ 151	$ 63	$ 11[(a)]	$ 108[(b)]	$ 117
Deferred tax valuation allowance	1	—	—	—	1
Reserve for obsolete materials	1	—	—	—	1

(a) Primarily charges for late payments.
(b) Write−off of individual accounts receivable.

[Table of Contents](#)

(b) Exhibits required by Item 601 of Regulation S−K:

Certain of the following exhibits are incorporated herein by reference under Rule 12b−32 of the Securities and Exchange Act of 1934, as amended. Certain other instruments which would otherwise be required to be listed below have not been so listed because such instruments do not authorize securities in an amount which exceeds 10% of the total assets of the applicable registrant and its subsidiaries on a consolidated basis and the relevant registrant agrees to furnish a copy of any such instrument to the Commission upon request.

Exhibit No.	Description
2−1	Amended and Restated Agreement and Plan of Merger dated as of October 20, 2000, among PECO Energy Company, Exelon Corporation and Unicom Corporation (File No. 0−01401, PECO Energy Company Form 10−Q for the quarter ended September 30, 2000, Exhibit 2−1).
2−2	Purchase Agreement dated as of August 30, 2010 by and between Deere & Company and Generation (File No. 1−16169, Form 10−Q for the quarter ended September 30, 2010, Exhibit 2−1).
2−3	Purchase Agreement dated as of April 28, 2011 by and between Exelon Corporation, Bolt Acquisition Corporation and Constellation Energy Group, Inc. (File No. 333−85496, Form 8−K dated April 28, 2011, Exhibit No. 2−1)
3−1	Amended and Restated Articles of Incorporation of Exelon Corporation, as amended May 8, 2007 (File No. 001−16169, Form 10−Q for the quarter ended September 30, 2008, Exhibit 3−1−2).
3−2	Exelon Corporation Amended and Restated Bylaws, as amended January 26, 2010.
3−3	Certificate of Formation of Exelon Generation Company, LLC (Registration Statement No. 333−85496, Form S−4, Exhibit 3−1).
3−4	First Amended and Restated Operating Agreement of Exelon Generation Company, LLC executed as of January 1, 2001 (File No. 333−85496, 2003 Form 10−K, Exhibit 3−8).
3−5	Restated Articles of Incorporation of Commonwealth Edison Company Effective February 20, 1985, including Statements of Resolution Establishing Series, relating to the establishment of three new series of Commonwealth Edison Company preference stock known as the “$9.00 Cumulative Preference Stock,” the “$6.875 Cumulative Preference Stock” and the “$2.425 Cumulative Preference Stock” (File No. 1−1839, 1994 Form 10−K, Exhibit 3−2).
3−6	Commonwealth Edison Company Amended and Restated By−Laws, Effective January 23, 2006 As Further Amended January 28, 2008 and July 27, 2009. (File No. 001−16169, Form 8−K dated July 27, 2009, Exhibit 3.1).
3−7	Amended and Restated Articles of Incorporation of PECO Energy Company (File No. 1−01401, 2000 Form 10−K, Exhibit 3−3).
3−8	PECO Energy Company Amended Bylaws (File 000−16844, Form 8−K dated May 6, 2009, Exhibit 99.1).
4−1	First and Refunding Mortgage dated May 1, 1923 between The Counties Gas and Electric Company (predecessor to PECO Energy Company) and Fidelity Trust Company, Trustee (U.S. Bank National Association, as current successor trustee), (Registration No. 2−2281, Exhibit B−1).

[Table of Contents](#)

4−1−1 Supplemental Indentures to PECO Energy Company's First and Refunding Mortgage:

Dated as of	File Reference	Exhibit No.
May 1, 1927	2−2881	B−1(c)
March 1, 1937	2−2881	B−1(g)
December 1, 1941	2−4863	B−1(h)
November 1, 1944	2−5472	B−1(i)
December 1, 1946	2−6821	7−1(j)
September 1, 1957	2−13562	2(b)−17
May 1, 1958	2−14020	2(b)−18
March 1, 1968	2−34051	2(b)−24
March 1, 1981	2−72802	4−46
March 1, 1981	2−72802	4−47
December 1, 1984	1−01401, 1984 Form 10−K	4−2(b)
March 1, 1993	1−01401, 1992 Form 10−K	4(e)−86
May 1, 1993	1−01401, March 31, 1993 Form 10−Q	4(e)−88
May 1, 1993	1−01401, March 31, 1993 Form 10−Q	4(e)−89
September 15, 2002	1−01401, September 30, 2002 Form 10−Q	4−1
October 1, 2002	1−01401, September 30, 2002 Form 10−Q	4−2
April 15, 2003	0−16844, March 31, 2003 Form 10−Q	4.1
April 15, 2004	0−6844, September 30, 2004 Form 10−Q	4−1−1
September 15, 2006	000−16844, Form 8−K dated September 25, 2006	4.1
March 1, 2007	000−16844, Form 8−K dated March 19, 2007	4.1
February 15, 2008	0−16844, Form 8−K dated March 3, 2008	4.1
February 15, 2008	0−16844, Form 8−K, dated March 5, 2008	
September 15, 2008	000−16844, Form 8−K dated October 2, 2008	4.1
March 15, 2009	000−16844, Form 8−K dated March 26, 2009	4.1

4−2 Exelon Corporation Dividend Reinvestment and Stock Purchase Plan (Registration Statement No. 333−84446, Form S−3, Prospectus).

4−3 Mortgage of Commonwealth Edison Company to Illinois Merchants Trust Company, Trustee (BNY Mellon Trust Company of Illinois, as current successor Trustee), dated July 1, 1923, as supplemented and amended by Supplemental Indenture thereto dated August 1, 1944. (File No. 2−60201, Form S−7, Exhibit 2−1).

Table of Contents

4−3−1 Supplemental Indentures to Commonwealth Edison Company Mortgage.

Dated as of	File Reference	Exhibit No.
August 1, 1946	2−60201, Form S−7	2−1
April 1, 1953	2−60201, Form S−7	2−1
March 31, 1967	2−60201, Form S−7	2−1
April 1,1967	2−60201, Form S−7	2−1
February 28, 1969	2−60201, Form S−7	2−1
May 29, 1970	2−60201, Form S−7	2−1
June 1, 1971	2−60201, Form S−7	2−1
April 1, 1972	2−60201, Form S−7	2−1
May 31, 1972	2−60201, Form S−7	2−1
June 15, 1973	2−60201, Form S−7	2−1
May 31, 1974	2−60201, Form S−7	2−1
June 13, 1975	2−60201, Form S−7	2−1
May 28, 1976	2−60201, Form S−7	2−1
June 3, 1977	2−60201, Form S−7	2−1
May 17, 1978	2−99665, Form S−3	4−3
August 31, 1978	2−99665, Form S−3	4−3
June 18, 1979	2−99665, Form S−3	4−3
June 20, 1980	2−99665, Form S−3	4−3
April 16, 1981	2−99665, Form S−3	4−3
April 30, 1982	2−99665, Form S−3	4−3
April 15, 1983	2−99665, Form S−3	4−3
April 13, 1984	2−99665, Form S−3	4−3
April 15, 1985	2−99665, Form S−3	4−3
April 15, 1986	33−6879, Form S−3	4−9
April 15, 1993	33−64028, Form S−3	4−13
June 15, 1993	1−1839, Form 8−K dated May 21, 1993	4−1
January 15, 1994	1−1839, 1993 Form 10−K	4−15
March 1, 2002	1−1839, 2001 Form 10−K	4−4−1
June 1, 2002	333−99363, Form S−3	4−1−1 (B)
October 7, 2002	333−9715, Form S−4	4−1−3
January 13, 2003	1−1839, Form 8−K dated January 22, 2003	4−4
March 14, 2003	1−1839, Form 8−K dated April 7, 2003	4−4
February 22, 2006	1−1839, Form 8−K dated March 6, 2006	4.1
August 1, 2006	1−1839, Form 8−K dated August 28, 2006	4.1

Dated as of	File Reference	Exhibit No.
September 15, 2006	1−1839, Form 8−K dated October 2, 2006	4.1
December 1, 2006	1−1839, Form 8−K dated December 19, 2006	4.1
March 1, 2007	1−1839, Form 8−K dated March 23, 2007	4.1
August 30, 2007	1−1839, Form 8−K dated September 10, 2007	4.1
December 20, 2007	1−1839, Form 8−K dated January 16, 2008	4.1
March 10, 2008	1−1839, Form 8−K dated March 27, 2008	4.1
April 23, 2008	001−01839, Form 8−K dated May 12, 2008	4.1
June 12, 2008	001−01839, Form 8−K dated June 27, 2008	4.1
July 12, 2010	001−01839, Form 8−K dated August 2, 2010	4.1
January 4, 2011	001−01839, Form 8−K dated January 18, 2011	4.1
August 22, 2011	001−01839, Form 8−K dated September 7, 2011	4.1

Exhibit No.	Description
4−3−2	Instrument of Resignation, Appointment and Acceptance dated as of February 20, 2002, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923, and Indentures Supplemental thereto, regarding corporate trustee (File No. 1−1839, 2001 Form 10−K, Exhibit 4−4−2).
4−3−3	Instrument dated as of January 31, 1996, under the provisions of the Mortgage of Commonwealth Edison Company dated July 1, 1923 and Indentures Supplemental thereto, regarding individual trustee (File No. 1−1839, 1995 Form 10−K, Exhibit 4−29).
4−4	Indenture dated as of September 1, 1987 between Commonwealth Edison Company and Citibank, N.A., (U.S. Bank National Association, as current successor trustee) Trustee relating to Notes (File No. 33−20619, Form S−3, Exhibit 4−13).
4−4−1	Supplemental Indentures to aforementioned Indenture.

Dated as of	File Reference	Exhibit No.
July 14, 1989	33−32929, Form S−3	4−16

Exhibit No.	Description
4−5	Indenture dated December 19, 2003 between Generation and U.S. Bank National Association (File No. 333−85496, 2003 Form 10−K, Exhibit 4−6).
4−6	Indenture to Subordinated Debt Securities dated as of June 24, 2003 between PECO Energy Company, as Issuer, and U.S. Bank National Association, as Trustee (File No. 0−16844, Form 10−Q for the quarter ended June 30, 2003, Exhibit 4.1).
4−7	Preferred Securities Guarantee Agreement between PECO Energy Company, as Guarantor, and U.S. Bank National Association, as Trustee, dated as of June 24, 2003 (File No. 0−16844, June 30, 2003 Form 10−Q, Exhibit 4.2).

Exhibit No.	Description
4−8	PECO Energy Capital Trust IV Amended and Restated Declaration of Trust among PECO Energy Company, as Sponsor, U.S. Bank Trust National Association, as Delaware Trustee and Property Trustee, and J. Barry Mitchell, George R. Shicora and Charles S. Walls as Administrative Trustees dated as of June 24, 2003 (File No. 0−16844, June 30, 2003 Form 10−Q, Exhibit 4.3).
4−9	Indenture dated May 1, 2001 between Exelon and The Bank of New York Mellon Trust Company, National Association, as trustee (File No. 1−16169, June 30, 2005 Form 10−Q, Exhibit 4−10).
4−10	Form of $800,000,000 4.90% senior notes due 2015 dated June 9, 2005 issued by Exelon Corporation (File No. 1−16169, Form 8−K dated June 9, 2005, Exhibit 99.2).
4−11	Form of $500,000,000 5.625% senior notes due 2035 dated June 9, 2005 issued by Exelon Corporation (File No. 1−16169, Form 8−K dated June 9, 2005, Exhibit 99.3).
4−12	Indenture dated as of September 28, 2007 from Generation to U.S. Bank National Association, as trustee (File 333−85496, Form 8−K dated September 28, 2007, Exhibit 4.1).
4−13	Pollution Control Note dated as of February 15, 2008 from PECO to U.S. Bank National Association, as trustee (File 0−16844, Form 8−K dated March 5, 2008, Exhibit 4.2).
4−14	Form of 5.20% Generation Senior Note due 2019 (File 333−85496, Form 8−K dated September 23, 2009, Exhibit 4.1).
4−15	Form of 6.25% Generation Senior Note due 2039 (File 333−85496, Form 8−K dated September 23, 2009, Exhibit 4.2).
4−16	Form of 4.00% Generation Senior Note due 2020 (File No. 333−85496, Form 8−K dated September 30, 2010, Exhibit 4.1).
4−17	Form of 5.75% Generation Senior Note due 2041 (File No. 333−85496, Form 8−K dated September 30, 2010, Exhibit 4.2).
10−1	Exelon Corporation Deferred Non−Employee Directors' Deferred Stock Unit Plan (As Amended and Restated Effective January 1, 2011). *
10−2	Exelon Corporation Retirement Program (As Amended and Restated Effective January 1, 2010).
10−3	Exelon Corporation Deferred Compensation Plan for Directors (as amended and restated Effective January 1, 2011). *
10−4	Exelon Corporation Long−Term Incentive Plan As Amended and Restated Effective January 28, 2002* (File No. 1−16169, Exelon Proxy Statement dated March 13, 2002, Appendix B).
10−5−1	Form of Restricted Stock Award Agreement under the Exelon Corporation Long−Term Incentive Plan* (File No. 1−16169, 2001 Form 10−K, Exhibit 10−6−1).
10−5−2	Forms of Transferable Stock Option Award Agreement under the Exelon Corporation Long−Term Incentive Plan* (File No. 1−16169, 2001 Form 10−K, Exhibit 10−6−2).
10−5−3	Forms of Stock Option Award Agreement under the Exelon Corporation Long−Term Incentive Plan* (File No. 1−16169, 2001 Form 10−K, Exhibit 10−6−3).
10−6	Exelon Corporation Employee Savings Plan (As Amended and Restated Effective January 1, 2010).

Exhibit No.	Description
10−7	Exelon Corporation Cash Balance Pension Plan (As Amended and Restated Effective January 1, 2010).
10−8	Unicom Corporation Deferred Compensation Unit Plan, as amended *(File Nos. 1−11375 and 1−1839, 1995 Form 10−K, Exhibit 10−12).
10−9	Amendment Number One to the Unicom Corporation Deferred Compensation Unit Plan, as amended January 1, 2008 * (File No. 001−16169, 2008 Form 10−K, Exhibit 10.16).
10−10	Unicom Corporation Retirement Plan for Directors, as amended *(Registration Statement No. 333−49780, Form S−8, Exhibit 4−12).
10−11	Commonwealth Edison Company Retirement Plan for Directors, as amended *(Registration Statement No. 333−49780, Form S−8, Exhibit 4−13).
10−12	Exelon Corporation Supplemental Management Retirement Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001−16169, 2008 Form 10−K, Exhibit 10.19).
10−13	PECO Energy Company Supplemental Pension Benefit Plan (As Amended and Restated Effective January 1, 2009) (File No. 000−16844, 2008 Form 10−K, Exhibit 10.20).
10−14	Exelon Corporation Annual Incentive Plan for Senior Executives Effective January 1, 2004 (As Amended and Restated Effective January 1, 2009) * (File No. 001−16169, 2009 Form 10−K, Exhibit 10.21).
10−15	Form of change in control employment agreement for senior executives Effective January 1, 2009 * (File No. 001−16169. 2008 Form 10−K, Exhibit 10.23).
10−16	Form of change in control employment agreement (amended and restated as of January 1, 2009) * (File No. 001−16169, 2008 Form 10−K, Exhibit 10.24).
10−17	Restatement of the Exelon Corporation Employee Stock Purchase Plan, Effective May 1, 2004 and Appendix One thereto. (File No. 1−16169, 2004 Form 10−K, Exhibit 10−54).
10−18	Exelon Corporation 2006 Long−Term Incentive Plan (Registration Statement No. 333−122704, Form S−4, Joint Proxy Statement−Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex H).
10−19	Form of Stock Option Grant Instrument under the Exelon Corporation 2006 Long−Term Incentive Plan (File No. 1−16169, Form 8−K filed January 27, 2006, Exhibit 99.2).
10−20	Exelon Corporation Employee Stock Purchase Plan for Unincorporated Subsidiaries (Registration Statement No. 333−122704, Form S−4, Joint Proxy Statement−Prospectus pursuant to Rule 424(b)(3) filed June 3, 2005, Annex I).
10−21	Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No. 001−16169, 2008 Form 10−K, Exhibit 10.29).
10−22	Form of Separation Agreement under Exelon Corporation Senior Management Severance Plan (As Amended and Restated Effective January 1, 2009) * (File No, 001−16169, 2008 Form 10−K, Exhibit 10.30).
10−23	Facility Credit Agreement, dated as of November 4, 2010, among Generation and UBS AG, Stamford Branch (File No. 333−85496, Form 8−K dated February 22, 2011, Exhibit No. 10−1).
10−24	Exelon Corporation Executive Death Benefits Plan dated as of January 1, 2003 * (File No. 1−16169, 2006 Form 10−K, Exhibit 10−52).

Table of Contents

Exhibit No.	Description
10−25	First Amendment to Exelon Corporation Executive Death Benefits Plan, Effective January 1, 2006 * (File No. 1−16169, 2006 Form 10−K, Exhibit 10−53).
10−26	Amendment Number One to the Exelon Corporation 2006 Long−Term Incentive Plan, Effective December 4, 2006 (File No. 1−16169, 2006 Form 10−K, Exhibit 10−54).
10−27	Amendment Number Two to the Exelon Corporation 2006 Long−Term Incentive Plan (As Amended and Restated Effective January 28, 2002), Effective December 4, 2006 (File No. 1−16169, 2006 Form 10−K, Exhibit 10−55).
10−28	Exelon Corporation Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005) (File No. 1−16169, 2006 Form 10−K, Exhibit 10−56).
10−29	Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1−16169, 2006 Form 10−K, Exhibit 10−57).
10−30	Commonwealth Edison Company Long−Term Incentive Plan, Effective January 1, 2007 (File No. 1−16169, March 31, 2007 Form 10−Q, Exhibit 10−1).
10−31	Amendment Number One to the Exelon Corporation Stock Deferral Plan (As Amended and Restated Effective January 1, 2005) (File No. 1−16169, June 30, 2007 Form 10−Q, Exhibit 10−3).
10−32	Restricted stock unit award agreement (File 1−16169, Form 8−K dated August 31, 2007, Exhibit 99.1).
10−33	Settlement Agreement by and between the City of Chicago and Commonwealth Edison Company Effective December 21, 2007. (File No. 001−1839, 2007 Form 10−K, Exhibit 10−56).
10−34	Amended and Restated Trade Receivables Purchase and Sale Agreement among PECO, Victory Receivables Corporation and The Bank of Tokyo−Mitsubishi UFJ, Ltd. dated as of December 20, 1988, as Amended and Restated as of November 14, 1995, as of January 1, 1999, as of November 14, 2000, as of November 14, 2005 and as Further Amended and Restated as of September 19, 2008 (File 000−16844, Form 8−K dated September 22, 2008, Exhibit 10.1).
10−35	Amendment No. 1 to Amended and Restated Trade Receivables Purchase and Sale Agreement among PECO Energy Company, Victory Receivables Corporation and The Bank of Tokyo−Mitsubishi UFJ, Ltd. (File 000−16844, Form 8−K dated September 17, 2009, Exhibit 10.1).
10−36	Third Amended and Restated Employment Agreement with John W. Rowe * (File 1−16169, Fork 8−K dated October 29, 2009, Exhibit 99.1).
10−37	Exelon Corporation 2011 Long−Term Incentive Plan (File No. 1−16169, Schedule 14A dated March 18, 2010, Appendix A).
10−38	Form of Change in Control Employment Agreement Effective February 10, 2011. *
10−39	Credit Agreement for $500,000,000 dated as of March 23, 2011 between Exelon Corporation and Various Financial Institutions (File No. 001−16169, Form 8−K dated March 23, 2011, Exhibit No. 10−2).
10−40	Credit Agreement $5,300,000,000 dated as of March 23, 2011 between Exelon Generation Company, LLC and Various Financial Institutions (File No. 333−85496, Form 8−K dated March 23, 2011, Exhibit No. 10−3).

Table of Contents

Exhibit No.	Description
10−41	Credit Agreement for $600,000,000 dated as of March 23, 2011 between PECO Energy Company and Various Financial Institutions File No. 000−16844, Form 8−K dated March 23, 2011, Exhibit No. 10−4).
14	Exelon Code of Conduct (File No. 1−16169, 2006 Form 10−K, Exhibit 14).
	Subsidiaries
21−1	Exelon Corporation
21−2	Exelon Generation Company, LLC
21−3	Commonwealth Edison Company
21−4	PECO Energy Company
	Consent of Independent Registered Public Accountants
23−1	Exelon Corporation
23−2	Exelon Generation Company, LLC
23−3	Commonwealth Edison Company
23−4	PECO Energy Company
	Power of Attorney (Exelon Corporation)
24−1	John A. Canning, Jr.
24−2	M. Walter D'Alessio
24−3	Nicholas DeBenedictis
24−4	Nelson A. Diaz
24−5	Sue L. Gin
24−6	Rosemarie B. Greco
24−7	Paul L. Joskow
24−8	Richard W. Mies
24−9	John M. Palms, Ph.D.
24−10	William C. Richardson
24−11	Thomas J. Ridge
24−12	John W. Rogers, Jr.
24−13	Stephen D. Steinour
24−14	Donald Thompson
	Power of Attorney (Commonwealth Edison Company)
24−15	James W. Compton
24−16	A. Steven Crown
24−17	Peter V. Fazio, Jr.
24−18	Sue L. Gin

Exhibit No.	Description
24−19	Michael Moskow
24−20	Jesse H. Ruiz
	Power of Attorney (PECO Energy Company)
24−21	M. Walter D'Alessio
24−22	Nelson A. Diaz
24−23	Rosemarie B. Greco
24−24	Charisse R. Lillie
24−25	Thomas J. Ridge
24−26	Ronald Rubin
	Certifications Pursuant to Rule 13a−14(a) and 15d−14(a) of the Securities and Exchange Act of 1934 as to the Annual Report on Form 10−K for the year ended December 31, 2010 filed by the following officers for the following registrants:
31−1	Filed by John W. Rowe for Exelon Corporation
31−2	Filed by Matthew F. Hilzinger for Exelon Corporation
31−3	Filed by John W. Rowe for Exelon Generation Company, LLC
31−4	Filed by Matthew F. Hilzinger for Exelon Generation Company, LLC
31−5	Filed by Frank M. Clark for Commonwealth Edison Company
31−6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
31−7	Filed by Denis P. O'Brien for PECO Energy Company
31−8	Filed by Phillip S. Barnett for PECO Energy Company
	Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code as to the Annual Report on Form 10−K for the year ended December 31, 2010 filed by the following officers for the following registrants:
32−1	Filed by John W. Rowe for Exelon Corporation
32−2	Filed by Matthew F. Hilzinger for Exelon Corporation
32−3	Filed by John W. Rowe for Exelon Generation Company, LLC
32−4	Filed by Matthew F. Hilzinger for Exelon Generation Company, LLC
32−5	Filed by Frank M. Clark for Commonwealth Edison Company
32−6	Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
32−7	Filed by Denis P. O'Brien for PECO Energy Company
32−8	Filed by Phillip S. Barnett for PECO Energy Company
101.INS**	XBRL Instance
101.SCH**	XBRL Taxonomy Extension Schema
101.CAL**	XBRL Taxonomy Extension Calculation

Exhibit No.	Description
101.DEF**	XBRL Taxonomy Extension Definition
101.LAB**	XBRL Taxonomy Extension Labels
101.PRE**	XBRL Taxonomy Extension Presentation

* Compensatory plan or arrangements in which directors or officers of the applicable registrant participate and which are not available to all employees.

** XBRL information will be considered to be furnished, not filed for the first two years of a company's submission of XBRL information.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2012.

EXELON CORPORATION

By: /s/ JOHN W. ROWE
Name: **John W. Rowe**
Title: **Chairman and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 9th day of February, 2012.

Signature	Title
/s/ JOHN W. ROWE **John W. Rowe**	Chairman and Chief Executive Officer (Principal Executive Officer)
/s/ MATTHEW F. HILZINGER **Matthew F. Hilzinger**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ DUANE M. DESPARTE **Duane M. DesParte**	Vice President and Corporate Controller (Principal Accounting Officer)

This annual report has also been signed below by Darryl M. Bradford, Attorney−in−Fact, on behalf of the following Directors on the date indicated:

John A. Canning, Jr.
M. Walter D'Alessio
Nicholas DeBenedictis
Nelson A. Diaz
Sue L. Gin
Rosemarie B. Greco
Paul L. Joskow
Richard W. Mies
John M. Palms, PhD.
William C. Richardson
Thomas J. Ridge
John W. Rogers, Jr.
Stephen D. Steinour
Donald Thompson

By: /s/ DARRYL M. BRADFORD February 9, 2012
Name: **Darryl M. Bradford**

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2012.

EXELON GENERATION COMPANY, LLC

By: /s/ JOHN W. ROWE
Name: **John W. Rowe**
Title: **Chairman**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 9th day of February, 2012.

Signature	Title
/s/ JOHN W. ROWE **John W. Rowe**	Chairman (Principal Executive Officer)
/s/ MATTHEW F. HILZINGER **Matthew F. Hilzinger**	Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ MATTHEW R. GALVANONI **Matthew R. Galvanoni**	Chief Accounting Officer (Principal Financial Officer)

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2012.

COMMONWEALTH EDISON COMPANY

By: /s/ FRANK M. CLARK
Name: **Frank M. Clark**
Title: **Chairman and Chief Executive Officer**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 9th day of February, 2012.

Signature	Title
/s/ FRANK M. CLARK **Frank M. Clark**	Chairman and Chief Executive Officer (Principal Executive Officer)
/s/ ANNE R. PRAMAGGIORE **Anne R. Pramaggiore**	President and Chief Operating Officer
/s/ JOSEPH R. TRPIK, JR. **Joseph R. Trpik, Jr.**	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ KEVIN J. WADEN **Kevin J. Waden**	Vice President and Controller (Principal Accounting Officer)
/s/ JOHN W. ROWE **John W. Rowe**	Director

This annual report has also been signed below by Frank M. Clark, Attorney−in−Fact, on behalf of the following Directors on the date indicated:

James W. Compton
A. Steven Crown
Peter V. Fazio, Jr.
Sue L. Gin
Michael Moskow
Jesse H. Ruiz

By: /s/ FRANK M. CLARK February 9, 2012
Name: **Frank M. Clark**

[Table of Contents](#)

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Chicago and State of Illinois on the 9th day of February, 2012.

PECO ENERGY COMPANY

By: /s/ DENIS P. O'BRIEN
Name: **Denis P. O'Brien**
Title: **Chief Executive Officer and President**

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on the 9th day of February, 2012.

Signature	Title
/s/ DENIS P. O'BRIEN **Denis P. O'Brien**	Chief Executive Officer and President (Principal Executive Officer)
/s/ PHILLIP S. BARNETT **Phillip S. Barnett**	Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ JORGE A. ACEVEDO **Jorge A. Acevedo**	Vice President and Controller (Principal Accounting Officer)
/s/ JOHN W. ROWE **John W. Rowe**	Chairman and Director

This annual report has also been signed below by Paul R. Bonney, Attorney−in−Fact, on behalf of the following Directors on the date indicated:

M. Walter D'Alessio
Nelson A. Diaz
Rosemarie B. Greco
Thomas J. Ridge
Ronald Rubin
Charisse R. Lillie

By: /s/ PAUL R. BONNEY — February 9, 2012
Name: **Paul R. Bonney**

Exhibit 21.1

Exelon Corporation Subsidiaries Listing

Affiliate	Jurisdiction of Formation
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
AllEnergy Gas & Electric Marketing Company, L.L.C.	Delaware
ATNP Finance Company	Delaware
AV Solar Ranch 1, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
BC Energy LLC	Minnesota
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
Big Top, LLC	Oregon
Blissfield Wind Energy, LLC	Delaware
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Bolt Acquisition Corporation	Maryland
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks−I LLC	Minnesota
Breezy Bucks−II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
ComEd Financing III	Delaware
ComEd Funding, LLC	Delaware
ComEd Transitional Funding Trust	Delaware
Commonwealth Edison Company	Illinois
Commonwealth Edison Company of Indiana, Inc.	Indiana
Conemaugh Fuels, LLC	Delaware
Constellation Sacramento Holding, LLC	Delaware
Cow Branch Wind Power, L.L.C.	Missouri
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
DAJAW Transmission LLC	Minnesota
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware
ENEH Services, LLC	Delaware

ETT Canada, Inc.	New Brunswick
Ewington Energy Systems LLC	Minnesota
Ex−FM, Inc.	New York
Ex−FME, Inc.	Delaware
Exelon AOG Holding #1, Inc.	Delaware
Exelon AOG Holding #2, Inc	Delaware
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Business Services Company, LLC	Delaware
Exelon Capital Trust I	Delaware
Exelon Capital Trust II	Delaware
Exelon Capital Trust III	Delaware
Exelon Corporation	Pennsylvania
Exelon Edgar, LLC	Delaware
Exelon Energy Company	Delaware
Exelon Energy Delivery Company, LLC	Delaware
Exelon Enterprises Company, LLC	Pennsylvania
Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Company, LLC	Pennsylvania
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton LLC	Delaware
Exelon International Commodities, LLC	Delaware
Exelon Investment Holdings, LLC	Illinois
Exelon Mechanical, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon New England Power Marketing, Limited Partnership	Delaware
Exelon Nuclear Partners International S.ar.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Nuclear Texas Holdings, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon Transmission Company, LLC	Delaware
Exelon Ventures Company, LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas

Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExTel Corporation, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
ExTex Retail Services Company, LLC	Delaware
F & M Holdings Company, L.L.C.	Delaware
Frontier I, L.P.	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
G−Flow Wind, LLC	Minnesota
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Plains Wind Power, LLC	Texas
Hot Springs Windfarm, LLC	Idaho
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota
Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
La Salle 1 NQF, LLC	Nevada
La Salle 2 NQF, LLC	Nevada
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
Newcosy, Inc.	Delaware
Northwind Thermal Technologies Canada Inc.	New Brunswick
NuStart Energy Development, LLC	Delaware
OldcoVSI, Inc.	Delaware
OldPecoGasCo, Company	Pennsylvania
Oregon Trail Windfarm, LLC	Oregon
OSP Servicios, S.A. de C.V.	Mexico
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada

PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, L.P.	Delaware
PECO Energy Company	Pennsylvania
PECO Wireless, LLC	Delaware
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
RITELine Illinois, LLC	Illinois
RITELine Indiana, LLC	Indiana
RITELine Transmission Development, LLC	Delaware
River Bend I, L.L.C.	Delaware
Roadrunner−I LLC	Minnesota
S & P Windfarms, LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog−I LLC	Minnesota
Salty Dog−II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Scherer Holdings 1, LLC	Delaware
Scherer Holdings 2, LLC	Delaware
Scherer Holdings 3, LLC	Delaware
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Spruce Equity Holdings, L.P.	Delaware
Spruce Holdings G.P. 2000, L.L.C.	Delaware
Spruce Holdings L.P. 2000, L.L.C.	Delaware
Spruce Holdings Trust	Delaware
Sunbelt I, L.L.C.	Delaware
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
Texas−Ohio Gas, Inc.	Texas
The Proprietors of the Susquehanna Canal	Maryland
Threemile Canyon Wind I, LLC	Oregon
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
UII, LLC	Illinois
URI, LLC	Illinois
Wagon Trail, LLC	Oregon
Wally’s Wind Farm LLC	Minnesota
Wansley Holdings 1, LLC	Delaware
Wansley Holdings 2, LLC	Delaware
Ward Butte Windfarm, LLC	Oregon
Wind Capital Holdings, LLC	Missouri
Windy Dog−1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware

Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exelon Generation Company, LLC Subsidiaries Listing

Affiliate	Jurisdiction of Formation
AgriWind LLC	Illinois
AgriWind Project L.L.C.	Delaware
AllEnergy Gas & Electric Marketing Company, LLC	Delaware
AV Solar Ranch I, LLC	Delaware
B & K Energy Systems, LLC	Minnesota
BC Energy LLC	Minnesota
Bellevue Wind Energy, LLC	Delaware
Bennett Creek Windfarm, LLC	Idaho
Big Top, LLC	Oregon
Blissfield Wind Energy, LLC	Delaware
Blue Breezes II, L.L.C.	Minnesota
Blue Breezes, L.L.C.	Minnesota
Braidwood 1 NQF, LLC	Nevada
Braidwood 2 NQF, LLC	Nevada
Breezy Bucks−I LLC	Minnesota
Breezy Bucks−II LLC	Minnesota
Butter Creek Power, LLC	Oregon
Byron 1 NQF, LLC	Nevada
Byron 2 NQF, LLC	Nevada
Cassia Gulch Wind Park LLC	Idaho
Cassia Wind Farm LLC	Idaho
Christoffer Transmission Systems, LLC	Minnesota
Christoffer Wind Energy I LLC	Minnesota
Christoffer Wind Energy II LLC	Minnesota
Christoffer Wind Energy III LLC	Minnesota
Christoffer Wind Energy IV LLC	Minnesota
Cisco Wind Energy LLC	Minnesota
Clinton NQF, LLC	Nevada
Conemaugh Fuels, LLC	Delaware
Constellation Sacramento Holding, LLC	Delaware
Cow Branch Wind Power, L.L.C.	Missouri
CP Windfarm, LLC	Minnesota
CR Clearing, LLC	Missouri
DAJAW Transmission LLC	Minnesota
DL Windy Acres, LLC	Minnesota
Dresden 1 NQF, LLC	Nevada
Dresden 2 NQF, LLC	Nevada
Dresden 3 NQF, LLC	Nevada
Elbridge Wind Farm, LLC	Delaware
ENEH Services, LLC	Delaware
Ewington Energy Systems, LLC	Minnesota
Exelon AOG Holding # 1, Inc.	Delaware
Exelon AOG Holding # 2, Inc.	Delaware
Exelon AVSR Holding, LLC	Delaware
Exelon AVSR, LLC	Delaware
Exelon Edgar, LLC	Delaware
Exelon Energy Company	Delaware

Exelon Framingham Development, LLC	Delaware
Exelon Framingham, LLC	Delaware
Exelon Generation Acquisitions, LLC	Delaware
Exelon Generation Consolidation, LLC	Nevada
Exelon Generation Finance Company, LLC	Delaware
Exelon Generation International, Inc.	Pennsylvania
Exelon Hamilton, LLC	Delaware
Exelon International Commodities, LLC	Delaware
Exelon New Boston, LLC	Delaware
Exelon New England Development, LLC	Delaware
Exelon New England Holdings, LLC	Delaware
Exelon New England Power Marketing, Limited Partnership	Delaware
Exelon Nuclear Partners International S.ar.l.	Luxembourg
Exelon Nuclear Partners, LLC	Delaware
Exelon Nuclear Security, LLC	Delaware
Exelon Nuclear Texas Holdings, LLC	Delaware
Exelon Peaker Development General, LLC	Delaware
Exelon Peaker Development Limited, LLC	Delaware
Exelon PowerLabs, LLC	Pennsylvania
Exelon SHC, LLC	Delaware
Exelon Solar Chicago LLC	Delaware
Exelon West Medway Development, LLC	Delaware
Exelon West Medway Expansion, LLC	Delaware
Exelon West Medway, LLC	Delaware
Exelon Wind 1, LLC	Texas
Exelon Wind 2, LLC	Texas
Exelon Wind 3, LLC	Texas
Exelon Wind 4, LLC	Texas
Exelon Wind 5, LLC	Texas
Exelon Wind 6, LLC	Texas
Exelon Wind 7, LLC	Texas
Exelon Wind 8, LLC	Texas
Exelon Wind 9, LLC	Texas
Exelon Wind 10, LLC	Texas
Exelon Wind 11, LLC	Texas
Exelon Wind Canada Inc.	Canada
Exelon Wind, LLC	Delaware
Exelon Wyman, LLC	Delaware
ExTex LaPorte Limited Partnership	Texas
ExTex Retail Services Company, LLC	Delaware
Four Corners Windfarm, LLC	Oregon
Four Mile Canyon Windfarm, LLC	Oregon
Frontier I, L.P.	Delaware
G−Flow Wind, LLC	Minnesota
Green Acres Breeze, LLC	Minnesota
Greensburg Wind Farm, LLC	Delaware
Harvest II Windfarm, LLC	Delaware
Harvest Windfarm, LLC	Michigan
High Plains Wind Power, LLC	Texas
Hot Springs Windfarm, LLC	Idaho
K & D Energy LLC	Minnesota
KC Energy LLC	Minnesota

Keystone Fuels, LLC	Delaware
KSS Turbines LLC	Minnesota
LaSalle 1 NQF, LLC	Nevada
LaSalle 2 NQF, LLC	Nevada
Limerick 1 NQF, LLC	Nevada
Limerick 2 NQF, LLC	Nevada
Loess Hills Wind Farm, LLC	Missouri
Marshall Wind 1, LLC	Minnesota
Marshall Wind 2, LLC	Minnesota
Marshall Wind 3, LLC	Minnesota
Marshall Wind 4, LLC	Minnesota
Marshall Wind 5, LLC	Minnesota
Marshall Wind 6, LLC	Minnesota
Michigan Wind 1, LLC	Delaware
Michigan Wind 2, LLC	Delaware
Minnesota Breeze, LLC	Minnesota
NuStart Energy Development, LLC	Delaware
Oregon Trail Windfarm, LLC	Oregon
Oyster Creek NQF, LLC	Nevada
Pacific Canyon Windfarm, LLC	Oregon
Peach Bottom 1 NQF, LLC	Nevada
Peach Bottom 2 NQF, LLC	Nevada
Peach Bottom 3 NQF, LLC	Nevada
Prairie Wind Power LLC	Minnesota
Quad Cities 1 NQF, LLC	Nevada
Quad Cities 2 NQF, LLC	Nevada
River Bend I, L.L.C.	Delaware
Roadrunner−I LLC	Minnesota
S & P Windfarms, LLC	Minnesota
Sacramento PV Energy, LLC	Delaware
Salem 1 NQF, LLC	Nevada
Salem 2 NQF, LLC	Nevada
Salty Dog−I LLC	Minnesota
Salty Dog−II LLC	Minnesota
Sand Ranch Windfarm, LLC	Oregon
Shane’s Wind Machine LLC	Minnesota
Shooting Star Wind Project, LLC	Delaware
Sunbelt I, L.L.C.	Delaware
Sunset Breeze, LLC	Minnesota
Tamuin International, Inc.	Delaware
TEG Holdings, LLC	Delaware
Texas Ohio Gas, Inc.	Texas
The Proprietors of the Susquehanna Canal	Maryland
Threemile Canyon Wind I, LLC	Oregon
TMI NQF, LLC	Nevada
Tuana Springs Energy, LLC	Idaho
Wagon Trail, LLC	Oregon
Wally’s Wind Farm LLC	Minnesota
Ward Butte Windfarm, LLC	Oregon
Wind Capital Holdings, LLC	Missouri
Windy Dog−1 LLC	Minnesota
Wolf Hollow I, L.P.	Delaware

Wolf Wind Enterprises, LLC	Minnesota
Wolf Wind Transmission, LLC	Minnesota
Zion 1 NQF, LLC	Nevada
Zion 2 NQF, LLC	Nevada

Exhibit 21.3

Commonwealth Edison Company Subsidiaries Listing

Affiliate	**Jurisdiction of Formation**
ComEd Financing III	Delaware
ComEd Funding, LLC	Delaware
ComEd Transitional Funding Trust	Delaware
Commonwealth Edison Company of Indiana, Inc.	Indiana
RITELine Illinois, LLC	Illinois

Exhibit 21.4

PECO Energy Company Subsidiaries Listing

Affiliate	Jurisdiction of Formation
ATNP Finance Company	Delaware
ExTel Corporation, LLC	Delaware
OldPecoGasCo, Company	Pennsylvania
PEC Financial Services, LLC	Pennsylvania
PECO Energy Capital Corp.	Delaware
PECO Energy Capital Trust III	Delaware
PECO Energy Capital Trust IV	Delaware
PECO Energy Capital Trust V	Delaware
PECO Energy Capital Trust VI	Delaware
PECO Energy Capital, LP	Delaware
PECO Wireless, LLC	Delaware

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S−3 (No. 333−164782) Form S−4 (No.333−175162) and on Form S−8 (No. 333−37082, 333−49780, 333−127377, and 333−61390) of Exelon Corporation of our report dated February 9, 2012 relating to the financial statements, financial statement schedules and the effectiveness of internal control over financial reporting of Exelon Corporation, which appears in this Form 10−K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S−3 (No. 333−164782−07) of Exelon Generation Company, LLC of our report dated February 9, 2012 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Exelon Generation Company, LLC, which appears in this Form 10−K.

/s/ PricewaterhouseCoopers LLP
Chicago,Illinois
February 9, 2012

Exhibit 23.3

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on Form S−3 (No. 333−158920) and on Form S−8 (No. 333−33847) of Commonwealth Edison Company of our report dated February 9, 2012 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of Commonwealth Edison Company, which appears in this Form 10−K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Exhibit 23.4

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statement on Form S−3 (No. 333−164782−03) of PECO Energy Company of our report dated February 9, 2012 relating to the financial statements, financial statement schedule and the effectiveness of internal control over financial reporting of PECO Energy Company, which appears in this Form 10−K.

/s/ PricewaterhouseCoopers LLP
Chicago, Illinois
February 9, 2012

Exhibit 24.1

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John A. Canning, Jr.** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John A. Canning, Jr.
John A. Canning, Jr.

DATE: February 6, 2012

Exhibit 24.2

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D'Alessio** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D'Alessio
M. Walter D'Alessio

DATE: February 7, 2012

Exhibit 24.3

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nicholas DeBenedictis** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nicholas DeBenedictis
Nicholas DeBenedictis

DATE: February 4, 2012

Exhibit 24.4

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 2, 2012

Exhibit 24.5

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin
Sue L. Gin

DATE: February 2, 2012

Exhibit 24.6

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Rosemarie B. Greco
Rosemarie B. Greco

DATE: February 3, 2012

Exhibit 24.7

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Paul Joskow** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Paul Joskow
Paul Joskow

DATE: February 5, 2012

Exhibit 24.8

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Richard W. Mies** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Richard W. Mies
Richard W. Mies

DATE: February 5, 2012

Exhibit 24.9

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John M. Palms** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John M. Palms
John M. Palms

DATE: February 2, 2012

Exhibit 24.10

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **William C. Richardson** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ William C. Richardson
William C. Richardson

DATE: February 3, 2012

Exhibit 24.11

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Thomas J. Ridge** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Thomas J. Ridge
Thomas J. Ridge

DATE: February 8, 2012

Exhibit 24.12

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **John W. Rogers, Jr.** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ John W. Rogers, Jr.
John W. Rogers, Jr.

DATE: February 7, 2012

Exhibit 24.13

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Stephen D. Steinour** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Stephen D. Steinour
Stephen D. Steinour

DATE: February 2, 2012

Exhibit 24.14

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Don Thompson** do hereby appoint John W. Rowe and Darryl M. Bradford, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Exelon Corporation, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Don Thompson
Don Thompson

DATE: February 6, 2012

Exhibit 24.15

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **James W. Compton** do hereby appoint Frank M. Clark and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ James W. Compton

James W. Compton

DATE: February 3, 2012

Exhibit 24.16

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **A. Steven Crown** do hereby appoint Frank M. Clark and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ A. Steven Crown
A. Steven Crown

DATE: February 2, 2012

Exhibit 24.17

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Peter V. Fazio, Jr.** do hereby appoint Frank M. Clark and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Peter V. Fazio, Jr.
Peter V. Fazio, Jr.

DATE: February 2, 2012

Exhibit 24.18

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Sue L. Gin** do hereby appoint Frank M. Clark and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Sue L. Gin
Sue L. Gin

DATE: February 2, 2012

Exhibit 24.19

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Michael Moskow** do hereby appoint Frank M. Clark and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Michael Moskow
Michael Moskow

DATE: February 6, 2012

Exhibit 24.20

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Jesse H. Ruiz** do hereby appoint Frank M. Clark and Thomas S. O'Neill, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of Commonwealth Edison Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Jesse H. Ruiz
Jesse H. Ruiz

DATE: February 7, 2012

Exhibit 24.21

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **M. Walter D’Alessio** do hereby appoint Denis P. O’Brien and Paul Bonney, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ M. Walter D’Alessio
M. Walter D’Alessio

DATE: February 7, 2012

Exhibit 24.22

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Nelson A. Diaz** do hereby appoint Denis P. O'Brien and Paul Bonney, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Nelson A. Diaz
Nelson A. Diaz

DATE: February 2, 2012

Exhibit 24.23

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Rosemarie B. Greco** do hereby appoint Denis P. O'Brien and Paul Bonney, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Rosemarie B. Greco

Rosemarie B. Greco

DATE: February 3, 2012

Exhibit 24.24

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Charisse R. Lillie** do hereby appoint Denis P. O'Brien and Paul Bonney, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Charisse R. Lillie
Charisse R. Lillie

DATE: February 3, 2012

Exhibit 24.25

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Thomas J. Ridge** do hereby appoint Denis P. O'Brien and Paul Bonney, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Thomas J. Ridge

Thomas J. Ridge

DATE: February 8, 2012

Exhibit 24.26

POWER OF ATTORNEY

KNOW ALL MEN BY THESE PRESENTS that I, **Ronald Rubin** do hereby appoint Denis P. O'Brien and Paul Bonney, or either of them, attorney for me and in my name and on my behalf to sign the annual Securities and Exchange Commission report on Form 10−K for 2011 of PECO Energy Company, together with any amendments thereto, to be filed with the Securities and Exchange Commission, and generally to do and perform all things necessary to be done in the premises as fully and effectually in all respects as I could do if personally present.

/s/ Ronald Rubin

Ronald Rubin

DATE: February 2, 2012

Exhibit 31−1

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, John W. Rowe, certify that:

1. I have reviewed this annual report on Form 10−K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ JOHN W. ROWE
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31−2

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Matthew F. Hilzinger, certify that:

1. I have reviewed this annual report on Form 10−K of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ Matthew F. Hilzinger
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 31−3

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, John W. Rowe, certify that:

1. I have reviewed this annual report on Form 10−K of Exelon Generation Company, LLC;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ JOHN W. ROWE
Chairman
(Principal Executive Officer)

Exhibit 31−4

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Matthew F. Hilzinger, certify that:

1. I have reviewed this annual report on Form 10−K of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and
5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 9, 2012

/s/ MATTHEW F. HILZINGER
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 31−5

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Frank M. Clark, certify that:

1. I have reviewed this annual report on Form 10−K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ FRANK M. CLARK
Chairman and Chief Executive Officer
(Principal Executive Officer)

Exhibit 31−6

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this annual report on Form 10−K of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ JOSEPH R. TRPIK, JR.
Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 31−7

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Denis P. O'Brien, certify that:

1. I have reviewed this annual report on Form 10−K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ Denis P. O'Brien
Chief Executive Officer and President
(Principal Executive Officer)

Exhibit 31−8

CERTIFICATION PURSUANT TO RULE 13a−14(a) AND 15d−14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this annual report on Form 10−K of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a−15(e) and 15d−15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a−15(f) and 15d−15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2012

/s/ PHILLIP S. BARNETT
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Exhibit 32−1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of Exelon Corporation for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 9, 2012

/s/ JOHN W. ROWE
John W. Rowe
Chairman and Chief Executive Officer

Exhibit 32−2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of Exelon Corporation for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

Date: February 9, 2012

/s/ MATTHEW F. HILZINGER

Matthew F. Hilzinger
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32−3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of Exelon Generation Company, LLC for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 9, 2012

/s/ JOHN W. ROWE

John W. Rowe
Chairman

Exhibit 32−4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of Exelon Generation Company, LLC for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

Date: February 9, 2012

/s/ MATTHEW F. HILZINGER
Matthew F. Hilzinger
Chief Financial Officer and Treasurer
(Principal Financial Officer)

Exhibit 32−5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of Commonwealth Edison Company for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 9, 2012

/s/ FRANK M. CLARK
Frank M. Clark
Chairman and Chief Executive Officer

Exhibit 32−6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of Commonwealth Edison Company for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

Date: February 9, 2012

/s/ JOSEPH R. TRPIK, JR.
Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32−7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of PECO Energy Company for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 9, 2012

/s/ DENIS P. O'BRIEN
Denis P. O'Brien
Chief Executive Officer and President

Exhibit 32−8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the Report on Form 10−K of PECO Energy Company for the year ended December 31, 2011, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

Date: February 9, 2012

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President and Chief Financial Officer