

EXELON CORP  
Form 10-Q  
April 29, 2015  
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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**

**Washington, D.C. 20549**

**FORM 10-Q**

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

**For the Quarterly Period Ended March 31, 2015**

**or**

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

	<b>Name of Registrant; State of Incorporation;</b>	
<b>Commission</b>	<b>Address of Principal Executive Offices; and</b>	<b>IRS Employer</b>
<b>File Number</b>	<b>Telephone Number</b>	<b>Identification</b>
		<b>Number</b>
1-16169	EXELON CORPORATION (a Pennsylvania corporation)  10 South Dearborn Street  P.O. Box 805379  Chicago, Illinois 60680-5379  (800) 483-3220	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company)  300 Exelon Way  Kennett Square, Pennsylvania 19348-2473  (610) 765-5959	23-3064219
1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation)  440 South LaSalle Street	36-0938600

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Chicago, Illinois 60605-1028

(312) 394-4321

000-16844

PECO ENERGY COMPANY  
(a Pennsylvania corporation)

23-0970240

P.O. Box 8699

2301 Market Street

Philadelphia, Pennsylvania 19101-8699

(215) 841-4000

1-1910

BALTIMORE GAS AND ELECTRIC COMPANY  
(a Maryland corporation)

52-0280210

2 Center Plaza

110 West Fayette Street

Baltimore, Maryland 21201-3708

(410) 234-5000

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes  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 whether the registrant is a large accelerated filer, an accelerated filer, a 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 Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
Exelon Corporation	x			
Exelon Generation Company, LLC			x	
Commonwealth Edison Company			x	
PECO Energy Company			x	
Baltimore Gas and Electric Company			x	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes  No

The number of shares outstanding of each registrant's common stock as of March 31, 2015 was:

Exelon Corporation Common Stock, without par value	861,243,550
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, \$12.50 par value	127,016,962
PECO Energy Company Common Stock, without par value	170,478,507
Baltimore Gas and Electric Company Common Stock, without par value	1,000

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<i>Exelon</i>	Exelon Corporation
<i>Generation</i>	Exelon Generation Company, LLC
<i>ComEd</i>	Commonwealth Edison Company
<i>PECO</i>	PECO Energy Company
<i>BGE</i>	Baltimore Gas and Electric Company
<i>BSC</i>	Exelon Business Services Company, LLC
<i>Exelon Corporate</i>	Exelon's holding company
<i>CENG</i>	Constellation Energy Nuclear Group, LLC
<i>Constellation</i>	Constellation Energy Group, Inc.
<i>Antelope Valley, AVSR</i>	Antelope Valley Solar Ranch One
<i>Exelon Transmission Company</i>	Exelon Transmission Company, LLC
<i>Exelon Wind</i>	Exelon Wind, LLC and Exelon Generation Acquisition Company, LLC
<i>Ventures</i>	Exelon Ventures Company, LLC
<i>AmerGen</i>	AmerGen Energy Company, LLC
<i>BondCo</i>	RSB BondCo LLC
<i>ComEd Financing III</i>	ComEd Financing III
<i>PEC L.P.</i>	PECO Energy Capital, L.P.
<i>PECO Trust III</i>	PECO Energy Capital Trust III
<i>PECO Trust IV</i>	PECO Energy Capital Trust IV
<i>BGE Trust II</i>	BGE Capital Trust II
<i>PETT</i>	PECO Energy Transition Trust
<i>Registrants</i>	Exelon, Generation, ComEd, PECO and BGE, collectively

**Other Terms and Abbreviations**

<i>Note of the Exelon 2014 Form 10-K</i>	Reference to a specific Combined Note to Consolidated Financial Statements within Exelon's 2014 Annual Report on Form 10-K
<i>1998 restructuring settlement</i>	PECO's 1998 settlement of its restructuring case mandated by the Competition Act
<i>Act 11</i>	Pennsylvania Act 11 of 2012
<i>Act 129</i>	Pennsylvania Act 129 of 2008
<i>AEC</i>	Alternative Energy Credit that is issued for each megawatt hour of generation from a qualified alternative energy source
<i>AEPS</i>	Pennsylvania Alternative Energy Portfolio Standards
<i>AEPS Act</i>	Pennsylvania Alternative Energy Portfolio Standards Act of 2004, as amended
<i>AESO</i>	Alberta Electric Systems Operator
<i>AFUDC</i>	Allowance for Funds Used During Construction
<i>ALJ</i>	Administrative Law Judge
<i>AMI</i>	Advanced Metering Infrastructure
<i>AMP</i>	Advanced Metering Program
<i>ARC</i>	Asset Retirement Cost
<i>ARO</i>	Asset Retirement Obligation
<i>ARP</i>	Title IV Acid Rain Program
<i>ARRA of 2009</i>	American Recovery and Reinvestment Act of 2009
<i>Block contracts</i>	Forward Purchase Energy Block Contracts
<i>CAIR</i>	Clean Air Interstate Rule
<i>CAISO</i>	California ISO
<i>CAMR</i>	Federal Clean Air Mercury Rule

**Table of Contents****GLOSSARY OF TERMS AND ABBREVIATIONS****Other Terms and Abbreviations**

<i>CERCLA</i>	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
<i>CFL</i>	Compact Fluorescent Light
<i>Clean Air Act</i>	Clean Air Act of 1963, as amended
<i>Clean Water Act</i>	Federal Water Pollution Control Amendments of 1972, as amended
<i>Competition Act</i>	Pennsylvania Electricity Generation Customer Choice and Competition Act of 1996
<i>CPI</i>	Consumer Price Index
<i>CPUC</i>	California Public Utilities Commission
<i>CSAPR</i>	Cross-State Air Pollution Rule
<i>CTC</i>	Competitive Transition Charge
<i>DC Circuit Court</i>	United States Court of Appeals for the District of Columbia Circuit
<i>DOE</i>	United States Department of Energy
<i>DOJ</i>	United States Department of Justice
<i>DSP</i>	Default Service Provider
<i>DSP Program</i>	Default Service Provider Program
<i>EDF</i>	Electricite de France SA
<i>EE&amp;C</i>	Energy Efficiency and Conservation/Demand Response
<i>EGR</i>	ExGen Renewables I, LLC
<i>EGS</i>	Electric Generation Supplier
<i>EGTP</i>	ExGen Texas Power, LLC
<i>EIMA</i>	Illinois Energy Infrastructure Modernization Act
<i>EPA</i>	United States Environmental Protection Agency
<i>ERCOT</i>	Electric Reliability Council of Texas
<i>ERISA</i>	Employee Retirement Income Security Act of 1974, as amended
<i>EROA</i>	Expected Rate of Return on Assets
<i>ESPP</i>	Employee Stock Purchase Plan
<i>FASB</i>	Financial Accounting Standards Board
<i>FERC</i>	Federal Energy Regulatory Commission
<i>FRCC</i>	Florida Reliability Coordinating Council
<i>FTC</i>	Federal Trade Commission
<i>GAAP</i>	Generally Accepted Accounting Principles in the United States
<i>GDP</i>	Gross Domestic Product
<i>GHG</i>	Greenhouse Gas
<i>GRT</i>	Gross Receipts Tax
<i>GSA</i>	Generation Supply Adjustment
<i>GWh</i>	Gigawatt hour
<i>HAP</i>	Hazardous air pollutants
<i>Health Care Reform Acts</i>	Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act of 2010
<i>IBEW</i>	International Brotherhood of Electrical Workers
<i>ICC</i>	Illinois Commerce Commission
<i>ICE</i>	Intercontinental Exchange
<i>Illinois Act</i>	Illinois Electric Service Customer Choice and Rate Relief Law of 1997
<i>Illinois EPA</i>	Illinois Environmental Protection Agency
<i>Illinois Settlement Legislation</i>	Legislation enacted in 2007 affecting electric utilities in Illinois
<i>Integrys</i>	Integrys Energy Services, Inc.
<i>IPA</i>	Illinois Power Agency
<i>IRC</i>	Internal Revenue Code

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<i>IRS</i>	Internal Revenue Service
<i>ISO</i>	Independent System Operator
<i>ISO-NE</i>	ISO New England Inc.
<i>ISO-NY</i>	New York Independent System Operator
<i>kV</i>	Kilovolt
<i>kW</i>	Kilowatt
<i>kWh</i>	Kilowatt-hour
<i>LIBOR</i>	London Interbank Offered Rate
<i>LILO</i>	Lease-In, Lease-Out
<i>LLRW</i>	Low-Level Radioactive Waste
<i>LTIP</i>	Long-Term Incentive Plan
<i>MATS</i>	U.S. EPA Mercury and Air Toxics Standard Rule
<i>MBR</i>	Market Based Rates Incentive
<i>MDE</i>	Maryland Department of the Environment
<i>MDPSC</i>	Maryland Public Service Commission
<i>MGP</i>	Manufactured Gas Plant
<i>MISO</i>	Midcontinent Independent System Operator, Inc.
<i>mmcf</i>	Million Cubic Feet
<i>Moody's</i>	Moody's Investor Service
<i>MOPR</i>	Minimum Offer Price Rule
<i>MRV</i>	Market-Related Value
<i>MW</i>	Megawatt
<i>MWh</i>	Megawatt hour
<i>NAAQS</i>	National Ambient Air Quality Standards
<i>n.m.</i>	not meaningful
<i>NAV</i>	Net Asset Value
<i>NDT</i>	Nuclear Decommissioning Trust
<i>NEIL</i>	Nuclear Electric Insurance Limited
<i>NERC</i>	North American Electric Reliability Corporation
<i>NGS</i>	Natural Gas Supplier
<i>NJDEP</i>	New Jersey Department of Environmental Protection
<i>Non-Regulatory Agreements Units</i>	Nuclear generating units or portions thereof whose decommissioning-related activities are not subject to contractual elimination under regulatory accounting including the CENG units (Calvert Cliffs, Nine Mile Point, and R.E. Ginna), Clinton, Oyster Creek, Three Mile Island, Zion (a former ComEd unit), and portions of Peach Bottom (a former PECO unit)
<i>NOSA</i>	Nuclear Operating Services Agreement
<i>NOV</i>	Notice of Violation
<i>NPDES</i>	National Pollutant Discharge Elimination System
<i>NRC</i>	Nuclear Regulatory Commission
<i>NSPS</i>	New Source Performance Standards
<i>NWPA</i>	Nuclear Waste Policy Act of 1982
<i>NYMEX</i>	New York Mercantile Exchange
<i>OCI</i>	Other Comprehensive Income
<i>OIESO</i>	Ontario Independent Electricity System Operator
<i>OPEB</i>	Other Postretirement Employee Benefits
<i>PA DEP</i>	Pennsylvania Department of Environmental Protection
<i>PAPUC</i>	Pennsylvania Public Utility Commission
<i>PGC</i>	Purchased Gas Cost Clause



**Table of Contents****GLOSSARY OF TERMS AND ABBREVIATIONS****Other Terms and Abbreviations**

<i>PHI</i>	Pepco Holdings, Inc.
<i>PJM</i>	PJM Interconnection, LLC
<i>POLR</i>	Provider of Last Resort
<i>POR</i>	Purchase of Receivables
<i>PPA</i>	Power Purchase Agreement
<i>PPL</i>	PPL Holtwood, LLC
<i>Price-Anderson Act</i>	Price-Anderson Nuclear Industries Indemnity Act of 1957
<i>PRP</i>	Potentially Responsible Parties
<i>PSEG</i>	Public Service Enterprise Group Incorporated
<i>PURTA</i>	Pennsylvania Public Realty Tax Act
<i>PV</i>	Photovoltaic
<i>RCRA</i>	Resource Conservation and Recovery Act of 1976, as amended
<i>REC</i>	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
<i>Regulatory Agreement Units</i>	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting including the former ComEd units (Braidwood, Bryon, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem)
<i>RES</i>	Retail Electric Suppliers
<i>RFP</i>	Request for Proposal
<i>Rider</i>	Reconcilable Surcharge Recovery Mechanism
<i>RGGI</i>	Regional Greenhouse Gas Initiative
<i>RMC</i>	Risk Management Committee
<i>RPM</i>	PJM Reliability Pricing Model
<i>RPS</i>	Renewable Energy Portfolio Standards
<i>RTEP</i>	Regional Transmission Expansion Plan
<i>RTO</i>	Regional Transmission Organization
<i>S&amp;P</i>	Standard & Poor's Ratings Services
<i>SEC</i>	United States Securities and Exchange Commission
<i>Senate Bill 1</i>	Maryland Senate Bill 1
<i>SERC</i>	SERC Reliability Corporation (formerly Southeast Electric Reliability Council)
<i>SERP</i>	Supplemental Employee Retirement Plan
<i>SGIG</i>	Smart Grid Investment Grant
<i>SGIP</i>	Smart Grid Initiative Program
<i>SILO</i>	Sale-In, Lease-Out
<i>SMP</i>	Smart Meter Program
<i>SMPIP</i>	Smart Meter Procurement and Installation Plan
<i>SNF</i>	Spent Nuclear Fuel
<i>SOA</i>	Society of Actuaries
<i>SOS</i>	Standard Offer Service
<i>SPP</i>	Southwest Power Pool
<i>Tax Relief Act of 2010</i>	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
<i>Upstream</i>	Natural gas and oil exploration and production activities
<i>VIE</i>	Variable Interest Entity
<i>WECC</i>	Western Electric Coordinating Council

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**FILING FORMAT**

This combined Form 10-Q is being filed separately by Exelon Corporation, Exelon Generation Company, LLC, Commonwealth Edison Company, PECO Energy Company and Baltimore Gas and Electric Company (Registrants). Information contained herein relating to any individual Registrant is filed by such Registrant on its own behalf. No Registrant makes any representation as to information relating to any other Registrant.

**FORWARD-LOOKING STATEMENTS**

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon's 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part I, Financial Information, ITEM 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 17; and (3) 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 the Registrants file with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. These documents are also available to the public from commercial document retrieval services, the website maintained by the SEC at [www.sec.gov](http://www.sec.gov) and the Registrants' websites at [www.exeloncorp.com](http://www.exeloncorp.com). Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

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**PART I. FINANCIAL INFORMATION**

**Item 1. Financial Statements**

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions, except per share data)</b>	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
<b>Operating revenues</b>	\$ 8,830	\$ 7,237
<b>Operating expenses</b>		
Purchased power and fuel	4,470	4,006
Purchased power and fuel from affiliates		334
Operating and maintenance	2,081	1,858
Depreciation and amortization	610	564
Taxes other than income	304	293
Total operating expenses	7,465	7,055
<b>Equity in losses of unconsolidated affiliates</b>		(19)
<b>Gain on sales of assets</b>	1	5
<b>Operating income</b>	1,366	168
<b>Other income and (deductions)</b>		
Interest expense, net	(335)	(217)
Interest expense to affiliates	(10)	(10)
Other, net	80	98
Total other income and (deductions)	(265)	(129)
<b>Income before income taxes</b>	1,101	39
<b>Income taxes</b>	363	(54)
<b>Net income</b>	738	93
<b>Net income attributable to noncontrolling interest and preference stock dividends</b>	45	3
<b>Net income attributable to common shareholders</b>	693	90
<b>Comprehensive income, net of income taxes</b>		
Net income	738	93
<b>Other comprehensive income (loss), net of income taxes</b>		
Pension and non-pension postretirement benefit plans:		
Prior service (benefit) cost reclassified to periodic benefit cost	(11)	1
Actuarial loss reclassified to periodic cost	54	34
Pension and non-pension postretirement benefit plans valuation adjustment	(26)	(13)
Unrealized gain (loss) on cash flow hedges	6	(25)
Unrealized gain on equity investments		12
Unrealized loss on foreign currency translation	(12)	(5)
Other comprehensive income	11	4

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<b>Comprehensive income</b>	\$ 749	\$ 97
<b>Average shares of common stock outstanding:</b>		
Basic	862	858
Diluted	867	861
<b>Earnings per average common share:</b>		
Basic	\$ 0.80	\$ 0.10
Diluted	\$ 0.80	\$ 0.10
<b>Dividends per common share</b>	\$ 0.31	\$ 0.31

Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2015</b>	<b>March 31, 2014</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 738	\$ 93
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	948	908
Impairment of long-lived assets		1
Gain on sales of assets	(1)	(5)
Deferred income taxes and amortization of investment tax credits	129	(48)
Net fair value changes related to derivatives	(91)	730
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(47)	(26)
Other non-cash operating activities	344	276
Changes in assets and liabilities:		
Accounts receivable	(270)	(606)
Inventories	291	80
Accounts payable, accrued expenses and other current liabilities	(607)	157
Option premiums received, net	5	15
Counterparty collateral received (posted), net	31	(677)
Income taxes	174	17
Pension and non-pension postretirement benefit contributions	(269)	(472)
Other assets and liabilities	115	(278)
Net cash flows provided by operating activities	1,490	165
<b>Cash flows from investing activities</b>		
Capital expenditures	(1,784)	(1,217)
Proceeds from nuclear decommissioning trust fund sales	1,681	1,825
Investment in nuclear decommissioning trust funds	(1,747)	(1,878)
Acquisition of businesses	(15)	
Proceeds from sale of long-lived assets	142	18
Proceeds from termination of direct financing lease investment		335
Change in restricted cash	(26)	(40)
Other investing activities	(2)	(54)
Net cash flows used in investing activities	(1,751)	(1,011)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(141)	638
Issuance of long-term debt	1,206	950
Retirement of long-term debt	(580)	(1,150)
Dividends paid on common stock	(269)	(266)
Proceeds from employee stock plans	8	7
Other financing activities	(16)	(28)
Net cash flows provided by financing activities	208	151
<b>Decrease in cash and cash equivalents</b>	<b>(53)</b>	<b>(695)</b>

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Cash and cash equivalents at beginning of period	1,878	1,609
Cash and cash equivalents at end of period	\$ 1,825	\$ 914

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 1,825	\$ 1,878
Restricted cash and cash equivalents	297	271
Accounts receivable, net		
Customer	3,702	3,482
Other	1,077	1,227
Mark-to-market derivative assets	1,117	1,279
Unamortized energy contract assets	209	254
Inventories, net		
Fossil fuel and emission allowances	266	579
Materials and supplies	1,035	1,024
Deferred income taxes	231	244
Regulatory assets	804	847
Assets held for sale	1	147
Other	793	865
<b>Total current assets</b>	<b>11,357</b>	<b>12,097</b>
<b>Property, plant and equipment, net</b>	<b>53,001</b>	<b>52,087</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	6,068	6,076
Nuclear decommissioning trust funds	10,712	10,537
Investments	568	544
Goodwill	2,672	2,672
Mark-to-market derivative assets	913	773
Unamortized energy contracts assets	558	549
Pledged assets for Zion Station decommissioning	308	319
Other	1,234	1,160
<b>Total deferred debits and other assets</b>	<b>23,033</b>	<b>22,630</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 87,391</b>	<b>\$ 86,814</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****EXELON CORPORATION AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 309	\$ 460
Long-term debt due within one year	1,260	1,802
Accounts payable	2,839	3,048
Accrued expenses	1,230	1,539
Payables to affiliates	8	8
Regulatory liabilities	421	310
Mark-to-market derivative liabilities	117	234
Unamortized energy contract liabilities	172	238
Other	1,018	1,123
Total current liabilities	7,374	8,762
<b>Long-term debt</b>	20,519	19,362
<b>Long-term debt to financing trusts</b>	648	648
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	13,218	13,019
Asset retirement obligations	7,446	7,295
Pension obligations	3,154	3,366
Non-pension postretirement benefit obligations	1,825	1,742
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,566	4,550
Mark-to-market derivative liabilities	491	403
Unamortized energy contract liabilities	189	211
Payable for Zion Station decommissioning	136	155
Other	2,166	2,147
Total deferred credits and other liabilities	34,212	33,909
Total liabilities <sup>(a)</sup>	62,753	62,681
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock (No par value, 2,000 shares authorized, 861 shares and 860 shares outstanding at March 31, 2015 and December 31, 2014, respectively)	16,731	16,709
Treasury stock, at cost (35 shares at both March 31, 2015 and December 31, 2014)	(2,327)	(2,327)
Retained earnings	11,334	10,910
Accumulated other comprehensive loss, net	(2,673)	(2,684)
Total shareholders equity	23,065	22,608
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,380	1,332
Total equity	24,638	24,133

<b>Total liabilities and shareholders' equity</b>	\$ 87,391	\$ 86,814
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- (a) Exelon's consolidated assets include \$8,182 million and \$8,160 million at March 31, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon's consolidated liabilities include \$2,702 million and \$2,723 million at March 31, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 - Variable Interest Entities.

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**EXELON CORPORATION AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY**

(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Preference Stock	Total Equity
<b>Balance, December 31, 2014</b>	894,568	\$ 16,709	\$ (2,327)	\$ 10,910	\$ (2,684)	\$ 1,332	\$ 193	\$ 24,133
Net income				693		42	3	738
Long-term incentive plan activity	1,156	12						12
Employee stock purchase plan issuances	255	8						8
Tax benefit on stock compensation		2						2
Changes in equity of noncontrolling interest						6		6
Common stock dividends				(269)				(269)
Preference stock dividends							(3)	(3)
Other comprehensive income, net of income taxes					11			11
<b>Balance, March 31, 2015</b>	895,979	\$ 16,731	\$ (2,327)	\$ 11,334	\$ (2,673)	\$ 1,380	\$ 193	\$ 24,638

See the Combined Notes to Consolidated Financial Statements

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**EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2015	2014
<b>Operating revenues</b>		
Operating revenues	\$ 5,629	\$ 4,056
Operating revenues from affiliates	211	334
Total operating revenues	5,840	4,390
<b>Operating expenses</b>		
Purchased power and fuel	3,426	3,008
Purchased power and fuel from affiliates	7	349
Operating and maintenance	1,162	938
Operating and maintenance from affiliates	149	149
Depreciation and amortization	254	211
Taxes other than income	122	105
Total operating expenses	5,120	4,760
<b>Equity in losses of unconsolidated affiliates</b>		(19)
<b>(Loss) gain on sales of assets</b>	(1)	5
<b>Operating income (loss)</b>	719	(384)
<b>Other income and (deductions)</b>		
Interest expense	(90)	(73)
Interest expense to affiliates, net	(12)	(12)
Other, net	94	85
Total other income and (deductions)	(8)	
<b>Income (loss) before income taxes</b>	711	(384)
<b>Income taxes</b>	226	(199)
<b>Net income (loss)</b>	485	(185)
<b>Net income attributable to noncontrolling interests</b>	42	
<b>Net income (loss) attributable to membership interest</b>	443	(185)
<b>Comprehensive income (loss), net of income taxes</b>		
Net income (loss)	485	(185)
<b>Other comprehensive income (loss), net of income taxes</b>		
Unrealized loss on cash flow hedges	(5)	(25)
Unrealized gain on equity investments		12
Unrealized loss on foreign currency translation	(12)	(5)
Unrealized loss on marketable securities		(3)

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Other comprehensive loss	(17)	(21)
<b>Comprehensive income (loss)</b>	<b>\$ 468</b>	<b>\$ (206)</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2015</b>	<b>March 31, 2014</b>
<b>Cash flows from operating activities</b>		
Net income (loss)	\$ 485	\$ (185)
Adjustments to reconcile net income (loss) to net cash flows provided by (used in) operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	591	557
Impairment of long-lived assets		1
Loss (gain) on sales of assets	1	(5)
Deferred income taxes and amortization of investment tax credits	89	(161)
Net fair value changes related to derivatives	(165)	737
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(47)	(26)
Other non-cash operating activities	45	89
Changes in assets and liabilities:		
Accounts receivable	24	(295)
Receivables from and payables to affiliates, net	(10)	3
Inventories	228	1
Accounts payable, accrued expenses and other current liabilities	(345)	128
Option premiums received, net	5	15
Counterparty collateral (posted) received, net	62	(699)
Income taxes	(104)	(35)
Pension and non-pension postretirement benefit contributions	(107)	(191)
Other assets and liabilities	85	(103)
<b>Net cash flows provided by (used in) operating activities</b>	<b>837</b>	<b>(169)</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(937)	(535)
Proceeds from nuclear decommissioning trust fund sales	1,681	1,825
Investment in nuclear decommissioning trust funds	(1,747)	(1,878)
Acquisition of businesses	(15)	
Proceeds from sale of long-lived assets	142	18
Change in restricted cash	(21)	9
Changes in Exelon intercompany money pool		44
Other investing activities	(2)	(77)
<b>Net cash flows used in investing activities</b>	<b>(899)</b>	<b>(594)</b>
<b>Cash flows from financing activities</b>		
Change in short-term borrowings	(1)	354
Issuance of long-term debt	806	300
Retirement of long-term debt	(18)	(532)
Retirement of long-term debt to affiliate	(550)	
Changes in Exelon intercompany money pool	936	
Distribution to member	(1,356)	(30)
Other financing activities	(3)	(21)
<b>Net cash flows provided by (used in) financing activities</b>	<b>(186)</b>	<b>71</b>

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<b>Decrease in cash and cash equivalents</b>	(248)	(692)
<b>Cash and cash equivalents at beginning of period</b>	780	1,258
<b>Cash and cash equivalents at end of period</b>	\$ 532	\$ 566

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 532	\$ 780
Restricted cash and cash equivalents	179	158
Accounts receivable, net		
Customer	2,320	2,295
Other	378	318
Mark-to-market derivative assets	1,116	1,276
Receivables from affiliates	115	113
Unamortized energy contract assets	209	254
Inventories, net		
Fossil fuel and emission allowances	232	465
Materials and supplies	841	847
Deferred income taxes	266	327
Assets held for sale	1	147
Other	530	658
<b>Total current assets</b>	<b>6,719</b>	<b>7,638</b>
Property, plant and equipment, net	23,414	22,945
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,712	10,537
Investments	122	104
Goodwill	47	47
Mark-to-market derivative assets	911	771
Prepaid pension asset	1,748	1,704
Pledged assets for Zion Station decommissioning	308	319
Unamortized energy contract assets	558	549
Deferred income taxes	3	3
Other	776	731
<b>Total deferred debits and other assets</b>	<b>15,185</b>	<b>14,765</b>
<b>Total assets<sup>(a)</sup></b>	<b>\$ 45,318</b>	<b>\$ 45,348</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 25	\$ 36
Long-term debt due within one year	75	58
Long-term debt to affiliates due within one year		556
Accounts payable	1,634	1,759
Accrued expenses	694	886
Payables to affiliates	110	107
Borrowings from Exelon intercompany money pool	936	
Mark-to-market derivative liabilities	97	214
Unamortized energy contract liabilities	172	238
Other	532	605
<b>Total current liabilities</b>	<b>4,275</b>	<b>4,459</b>
<b>Long-term debt</b>	<b>7,477</b>	<b>6,709</b>
<b>Long-term debt to affiliate</b>	<b>940</b>	<b>943</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	6,091	6,034
Asset retirement obligations	7,296	7,146
Non-pension postretirement benefit obligations	919	915
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,921	2,880
Mark-to-market derivative liabilities	121	105
Unamortized energy contract liabilities	189	211
Payable for Zion Station decommissioning	136	155
Other	764	719
<b>Total deferred credits and other liabilities</b>	<b>19,458</b>	<b>19,186</b>
<b>Total liabilities<sup>(a)</sup></b>	<b>32,150</b>	<b>31,297</b>
<b>Commitments and contingencies</b>		
<b>Equity</b>		
Member s equity		
Membership interest	8,951	8,951
Undistributed earnings	2,890	3,803
Accumulated other comprehensive income, net	(53)	(36)
<b>Total member s equity</b>	<b>11,788</b>	<b>12,718</b>
Noncontrolling interest	1,380	1,333
<b>Total equity</b>	<b>13,168</b>	<b>14,051</b>
<b>Total liabilities and equity</b>	<b>\$ 45,318</b>	<b>\$ 45,348</b>

- (a) Generation's consolidated assets include \$8,118 million and \$8,119 million at March 31, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Generation's consolidated liabilities include \$2,486 million and \$2,507 million at March 31, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 Variable Interest Entities.

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## EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

## CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

(In millions)	Member s Equity			Noncontrolling Interest	Total Equity
	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Income, net		
<b>Balance, December 31, 2014</b>	\$ 8,951	\$ 3,803	\$ (36)	\$ 1,333	\$ 14,051
Net income		443		42	485
Changes in equity of noncontrolling interest				5	5
Distribution to member		(1,356)			(1,356)
Other comprehensive loss, net of income taxes			(17)		(17)
<b>Balance, March 31, 2015</b>	\$ 8,951	\$ 2,890	\$ (53)	\$ 1,380	\$ 13,168

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**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2015	2014
<b>Operating revenues</b>		
Operating revenues	\$ 1,184	\$ 1,133
Operating revenues from affiliates	1	1
Total operating revenues	1,185	1,134
<b>Operating expenses</b>		
Purchased power	318	212
Purchased power from affiliate	9	108
Operating and maintenance	333	287
Operating and maintenance from affiliate	45	39
Depreciation and amortization	175	173
Taxes other than income	75	77
Total operating expenses	955	896
<b>Operating income</b>	230	238
<b>Other income and (deductions)</b>		
Interest expense, net	(81)	(77)
Interest expense to affiliates	(3)	(3)
Other, net	3	5
Total other income and (deductions)	(81)	(75)
<b>Income before income taxes</b>	149	163
<b>Income taxes</b>	59	65
<b>Net income</b>	90	98
<b>Comprehensive income</b>	\$ 90	\$ 98

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**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 90	\$ 98
Adjustments to reconcile net income to net cash flows provided by (used in) operating activities:		
Depreciation, amortization and accretion	175	173
Deferred income taxes and amortization of investment tax credits	35	35
Other non-cash operating activities	126	36
Changes in assets and liabilities:		
Accounts receivable	(38)	(64)
Receivables from and payables to affiliates, net	(2)	(19)
Inventories	(10)	2
Accounts payable, accrued expenses and other current liabilities	(126)	(57)
Income taxes	131	44
Pension and non-pension postretirement benefit contributions	(121)	(233)
Other assets and liabilities	(9)	(24)
Net cash flows provided by (used in) operating activities	251	(9)
<b>Cash flows from investing activities</b>		
Capital expenditures	(530)	(341)
Proceeds from sales of investments		3
Other investing activities	7	8
Net cash flows used in investing activities	(523)	(330)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(21)	350
Issuance of long-term debt	400	650
Retirement of long-term debt		(617)
Contributions from parent	14	38
Dividends paid on common stock	(75)	(76)
Other financing activities	(4)	(1)
Net cash flows provided by financing activities	314	344
<b>Increase in cash and cash equivalents</b>	<b>42</b>	<b>5</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>66</b>	<b>36</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 108</b>	<b>\$ 41</b>

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**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 108	\$ 66
Restricted cash	4	4
Accounts receivable, net		
Customer	503	477
Other	512	648
Receivables from affiliates	17	14
Inventories, net	135	125
Regulatory assets	317	349
Other	41	40
Total current assets	1,637	1,723
<b>Property, plant and equipment, net</b>	<b>16,099</b>	<b>15,793</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	866	852
Investments	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,603	2,571
Prepaid pension asset	1,619	1,551
Other	276	271
Total deferred debits and other assets	7,995	7,876
<b>Total assets</b>	<b>\$ 25,731</b>	<b>\$ 25,392</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$ 283	\$ 304
Long-term debt due within one year	260	260
Accounts payable	534	598
Accrued expenses	223	331
Payables to affiliates	84	84
Customer deposits	128	128
Regulatory liabilities	131	125
Deferred income taxes	44	63
Mark-to-market derivative liability	20	20
Other	69	73
<b>Total current liabilities</b>	<b>1,776</b>	<b>1,986</b>
<b>Long-term debt</b>	<b>6,099</b>	<b>5,698</b>
<b>Long-term debt to financing trust</b>	<b>206</b>	<b>206</b>
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	4,553	4,498
Asset retirement obligations	103	103
Non-pension postretirement benefits obligations	262	263
Regulatory liabilities	3,692	3,655
Mark-to-market derivative liability	221	187
Other	881	889
<b>Total deferred credits and other liabilities</b>	<b>9,712</b>	<b>9,595</b>
<b>Total liabilities</b>	<b>17,793</b>	<b>17,485</b>
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock	1,588	1,588
Other paid-in capital	5,484	5,468
Retained earnings	866	851
<b>Total shareholders equity</b>	<b>7,938</b>	<b>7,907</b>
<b>Total liabilities and shareholders equity</b>	<b>\$ 25,731</b>	<b>\$ 25,392</b>

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**COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY**

(Unaudited)

(In millions)	Common Stock	Other Paid- In Capital	Retained Deficit Unappropriated	Retained Earnings Appropriated	Total Shareholders Equity
<b>Balance, December 31, 2014</b>	\$ 1,588	\$ 5,468	\$ (1,639)	\$ 2,490	\$ 7,907
Net income			90		90
Appropriation of retained earnings for future dividends			(90)	90	
Common stock dividends				(75)	(75)
Contribution from parent		14			14
Parent tax matter indemnification		2			2
<b>Balance, March 31, 2015</b>	\$ 1,588	\$ 5,484	\$ (1,639)	\$ 2,505	\$ 7,938

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**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
<b>Operating revenues</b>		
Operating revenues	\$ 985	\$ 992
Operating revenues from affiliates		1
Total operating revenues	985	993
<b>Operating expenses</b>		
Purchased power and fuel	376	377
Purchased power from affiliate	62	87
Operating and maintenance	197	256
Operating and maintenance from affiliates	25	24
Depreciation and amortization	62	58
Taxes other than income	41	42
Total operating expenses	763	844
<b>Gain on sale of assets</b>	1	
<b>Operating income</b>	223	149
<b>Other income and (deductions)</b>		
Interest expense, net	(25)	(25)
Interest expense to affiliates	(3)	(3)
Other, net	2	2
Total other income and (deductions)	(26)	(26)
<b>Income before income taxes</b>	197	123
<b>Income taxes</b>	58	34
<b>Net income attributable to common shareholder</b>	\$ 139	\$ 89
<b>Comprehensive income</b>	\$ 139	\$ 89

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**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 139	\$ 89
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	62	58
Deferred income taxes and amortization of investment tax credits	5	(2)
Other non-cash operating activities	44	49
Changes in assets and liabilities:		
Accounts receivable	(115)	(110)
Receivables from and payables to affiliates, net	5	2
Inventories	34	45
Accounts payable, accrued expenses and other current liabilities	1	117
Income taxes	67	33
Pension and non-pension postretirement benefit contributions	(12)	(11)
Other assets and liabilities	(72)	(127)
<b>Net cash flows provided by operating activities</b>	<b>158</b>	<b>143</b>
<b>Cash flows from investing activities</b>		
Capital expenditures	(148)	(184)
Other investing activities	4	2
<b>Net cash flows used in investing activities</b>	<b>(144)</b>	<b>(182)</b>
<b>Cash flows from financing activities</b>		
Change in Exelon intercompany money pool	65	
Dividends paid on common stock	(70)	(80)
Other financing activities	(1)	
<b>Net cash flows used in financing activities</b>	<b>(6)</b>	<b>(80)</b>
<b>Increase in cash and cash equivalents</b>	<b>8</b>	<b>(119)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>30</b>	<b>217</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 38</b>	<b>\$ 98</b>

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**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 38	\$ 30
Restricted cash and cash equivalents	2	2
Accounts receivable, net		
Customer	390	320
Other	123	141
Receivables from affiliates	3	3
Inventories, net		
Fossil fuel	19	57
Materials and supplies	26	22
Deferred income taxes	70	69
Prepaid utility taxes	107	10
Regulatory assets	41	29
Other	30	31
Total current assets	849	714
<b>Property, plant and equipment, net</b>	<b>6,867</b>	<b>6,801</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	1,543	1,529
Investments	31	31
Receivable from affiliates	500	490
Prepaid pension asset	347	344
Other	32	34
Total deferred debits and other assets	2,453	2,428
<b>Total assets</b>	<b>\$ 10,169</b>	<b>\$ 9,943</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Accounts payable	\$ 334	\$ 337
Accrued expenses	109	91
Payables to affiliates	57	52
Borrowings from Exelon intercompany money pool	65	
Customer deposits	53	52
Regulatory liabilities	119	90
Other	31	31
Total current liabilities	768	653
<b>Long-term debt</b>		
	2,246	2,246
<b>Long-term debt to financing trusts</b>	184	184
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	2,708	2,671
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	287	287
Regulatory liabilities	662	657
Other	95	95
Total deferred credits and other liabilities	3,781	3,739
Total liabilities	6,979	6,822
<b>Commitments and contingencies</b>		
<b>Shareholder s equity</b>		
Common stock	2,439	2,439
Retained earnings	750	681
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,190	3,121
<b>Total liabilities and shareholder s equity</b>	<b>\$ 10,169</b>	<b>\$ 9,943</b>

See the Combined Notes to Consolidated Financial Statements

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**PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY**

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder s Equity
<b>Balance, December 31, 2014</b>	\$ 2,439	\$ 681	\$ 1	\$ 3,121
Net income		139		139
Common stock dividends		(70)		(70)
<b>Balance, March 31, 2015</b>	\$ 2,439	\$ 750	\$ 1	\$ 3,190

See the Combined Notes to Consolidated Financial Statements

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**BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES**  
**CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**

(Unaudited)

(In millions)	Three Months Ended March 31,	
	2015	2014
<b>Operating revenue</b>		
Operating revenue	\$ 1,029	\$ 1,038
Operating revenue from affiliates	7	16
Total operating revenues	1,036	1,054
<b>Operating expenses</b>		
Purchased power and fuel	350	409
Purchased power from affiliate	137	120
Operating and maintenance	156	163
Operating and maintenance from affiliates	26	25
Depreciation and amortization	106	108
Taxes other than income	57	60
Total operating expenses	832	885
<b>Operating income</b>	204	169
<b>Other income and (deductions)</b>		
Interest expense, net	(21)	(23)
Interest expense to affiliates	(4)	(4)
Other, net	4	4
Total other income and (deductions)	(21)	(23)
<b>Income before income taxes</b>	183	146
<b>Income taxes</b>	74	58
<b>Net income</b>	109	88
<b>Preference stock dividends</b>	3	3
<b>Net income attributable to common shareholder</b>	\$ 106	\$ 85
<b>Comprehensive income</b>	\$ 109	\$ 88

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENTS OF CASH FLOWS****(Unaudited)**

<b>(In millions)</b>	<b>Three Months Ended</b>	
	<b>2015</b>	<b>March 31, 2014</b>
<b>Cash flows from operating activities</b>		
Net income	\$ 109	\$ 88
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	106	108
Deferred income taxes and amortization of investment tax credits	33	27
Other non-cash operating activities	64	43
Changes in assets and liabilities:		
Accounts receivable	(141)	(132)
Receivables from and payables to affiliates, net	(8)	(8)
Inventories	38	33
Accounts payable, accrued expenses and other current liabilities	(8)	(16)
Counterparty collateral (posted) received, net	(27)	22
Income taxes	26	31
Pension and non-pension postretirement benefit contributions	(4)	(5)
Other assets and liabilities	93	44
Net cash flows provided by operating activities	281	235
<b>Cash flows from investing activities</b>		
Capital expenditures	(136)	(146)
Change in restricted cash	2	(47)
Other investing activities	2	6
Net cash flows used in investing activities	(132)	(187)
<b>Cash flows from financing activities</b>		
Changes in short-term borrowings	(120)	(66)
Dividends paid on preference stock	(3)	(3)
Dividends paid on common stock	(36)	
Other financing activities	(13)	13
Net cash flows used in financing activities	(172)	(56)
<b>Decrease in cash and cash equivalents</b>	<b>(23)</b>	<b>(8)</b>
<b>Cash and cash equivalents at beginning of period</b>	<b>64</b>	<b>31</b>
<b>Cash and cash equivalents at end of period</b>	<b>\$ 41</b>	<b>\$ 23</b>

See the Combined Notes to Consolidated Financial Statements

**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>ASSETS</b>		
<b>Current assets</b>		
Cash and cash equivalents	\$ 41	\$ 64
Restricted cash and cash equivalents	48	50
Accounts receivable, net		
Customer	489	390
Other	99	82
Inventories, net		
Gas held in storage	16	57
Materials and supplies	33	30
Deferred income taxes	15	6
Prepaid utility taxes	30	59
Regulatory assets	187	214
Other	4	5
Total current assets	962	957
<b>Property, plant and equipment, net</b>	<b>6,280</b>	<b>6,204</b>
<b>Deferred debits and other assets</b>		
Regulatory assets	491	510
Investments	12	12
Prepaid pension asset	357	370
Other	28	25
Total deferred debits and other assets	888	917
<b>Total assets<sup>(a)</sup></b>	<b>\$ 8,130</b>	<b>\$ 8,078</b>

See the Combined Notes to Consolidated Financial Statements



**Table of Contents****BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED BALANCE SHEETS****(Unaudited)**

(In millions)	March 31, 2015 (Unaudited)	December 31, 2014
<b>LIABILITIES AND SHAREHOLDERS EQUITY</b>		
<b>Current liabilities</b>		
Short-term borrowings	\$	\$ 120
Long-term debt due within one year	75	75
Accounts payable	222	215
Accrued expenses	155	131
Deferred income taxes	36	52
Payables to affiliates	46	66
Customer deposits	95	92
Regulatory liabilities	124	44
Other	27	51
Total current liabilities	780	846
<b>Long-term debt</b>		
	1,867	1,867
<b>Long-term debt to financing trust</b>		
	258	258
<b>Deferred credits and other liabilities</b>		
Deferred income taxes and unamortized investment tax credits	1,924	1,865
Asset retirement obligations	18	17
Non-pension postretirement benefits obligations	211	212
Regulatory liabilities	187	200
Other	62	60
Total deferred credits and other liabilities	2,402	2,354
Total liabilities <sup>(a)</sup>	5,307	5,325
<b>Commitments and contingencies</b>		
<b>Shareholders equity</b>		
Common stock	1,360	1,360
Retained earnings	1,273	1,203
Total shareholder s equity	2,633	2,563
Preference stock not subject to mandatory redemption	190	190
Total equity	2,823	2,753
<b>Total liabilities and shareholders equity</b>	<b>\$ 8,130</b>	<b>\$ 8,078</b>

(a) BGE s consolidated assets include \$49 million and \$24 million at March 31, 2015 and December 31, 2014, respectively, of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include \$200 million and \$197

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million at March 31, 2015 and December 31, 2014, respectively, of BGE's consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents**BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES****CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY****(Unaudited)**

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference Stock Not Subject To Mandatory Redemption	Total Equity
<b>Balance, December 31, 2014</b>	\$ 1,360	\$ 1,203	\$ 2,563	\$ 190	\$ 2,753
Net income		109	109		109
Preference stock dividends		(3)	(3)		(3)
Common stock dividends	\$	\$ (36)	\$ (36)	\$	\$ (36)
<b>Balance, March 31, 2015</b>	\$ 1,360	\$ 1,273	\$ 2,633	\$ 190	\$ 2,823

See the Combined Notes to Consolidated Financial Statements

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

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

**1. Basis of Presentation (Exelon, Generation, ComEd, PECO and BGE)**

Exelon is a utility services holding company engaged through its principal subsidiaries in the energy generation and energy distribution businesses.

The energy generation business includes:

*Generation:* Physical delivery and marketing of owned and contracted electric generation capacity and provision of renewable and other energy-related products and services, and natural gas exploration and production activities. Generation has six reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions.

The energy delivery businesses include:

*ComEd:* Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in northern Illinois, including the City of Chicago.

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

*BGE:* Purchase and regulated retail sale of electricity and the provision of distribution and transmission services in central Maryland, including the City of Baltimore, and the purchase and regulated retail sale of natural gas and the provision of distribution services in central Maryland, including the City of Baltimore.

Each of the Registrant's consolidated financial statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. As a result of the Registrant's 2014 divestiture of certain unconsolidated affiliates considered integral to their operations and the consolidation of CENG during 2014, all Equity in earnings (losses) from unconsolidated affiliates will be presented below Income taxes in the Registrant's Statement of Operations and Comprehensive Income starting in the first quarter of 2015. For the three months ended March 31, 2015, Equity in earnings (losses) of unconsolidated affiliates was less than \$1 million.

The accompanying consolidated financial statements as of March 31, 2015 and 2014 and for the three months then ended are unaudited but, in the opinion of the management of each Registrant include all adjustments that are considered necessary for a fair statement of the Registrant's respective financial statements in accordance with GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. The December 31, 2014 Consolidated Balance Sheets were obtained from audited financial statements. Financial results for interim periods are not necessarily indicative of results that may be expected for any other interim period or for the fiscal year ending December 31, 2015. These Combined Notes to Consolidated Financial Statements have been prepared pursuant to the rules and regulations of the SEC for Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP have been condensed or omitted pursuant to such rules and regulations. These notes should be read in conjunction with the Combined Notes to Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2014 Form 10-K Reports.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)**

The following recently issued accounting standards are not yet required to be reflected in the combined financial statements of the Registrants.

***Customer s Accounting for Fees Paid in a Cloud Computing Arrangement***

In April 2015, the FASB issued authoritative guidance that clarifies the circumstances under which a cloud computing customer would account for the arrangement as a license of internal-use software. A cloud computing arrangement would include a software license if (1) the customer has a contractual right to take possession of the software at any time during the hosting period without significant penalty and (2) it is feasible for the customer to either run the software on its own hardware or contract with another party unrelated to the vendor to host the software. If the arrangement does not contain a software license, it would be accounted for as a service contract. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted. The guidance can be applied retrospectively to each prior reporting period presented or prospectively to arrangements entered into, or materially modified, after the effective date. The Registrants are currently assessing the impact this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance.

***Simplifying the Presentation of Debt Issuance Costs***

In April 2015, the FASB issued authoritative guidance that changes the presentation of debt issuance costs in financial statements. The new guidance requires entity s to present such costs in the balance sheet as a direct reduction to the related debt liability rather than as a deferred cost (i.e., an asset) as required by current guidance. The new standard does not change the recognition or measurement of debt issuance costs. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants are currently assessing the impact this guidance may have on their financial positions and disclosures, as well as whether to early adopt. The standard will not impact the results of operations and cash flows of the Registrants.

***Amendments to the Consolidation Analysis***

In February 2015, the FASB issued authoritative guidance that amends the consolidation analysis for variable interest entities (VIEs) as well as voting interest entities. The new guidance primarily (1) changes the assessment of limited partnerships as VIEs, (2) amends the effect that fees paid to a decision maker or service provider have on the VIE analysis, (3) amends how variable interests held by a reporting entity s related parties and de facto agents impact its consolidation conclusion, (4) clarifies how to determine whether equity holders (as a group) have power over an entity and (5) provides a scope exception for registered and similar unregistered money market funds. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2015. Early adoption is permitted. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of adoption (modified retrospective method). The Registrants are currently assessing the impact this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance. The Registrants do not plan to early adopt the standard.

***Revenue from Contracts with Customers***

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance. The guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016; and early adoption would not be permitted. However, in April 2015, FASB proposed a one year deferral of the effective date to annual reporting periods beginning on or after December 15, 2017. In addition, the FASB proposal would include an option to early adopt the guidance for annual periods beginning on or after December 15, 2016.

**3. Variable Interest Entities (Exelon, Generation, ComEd, PECO and BGE)**

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

At March 31, 2015 and December 31, 2014, Exelon, Generation, and BGE collectively consolidated six VIEs or VIE groups for which the applicable Registrant was the primary beneficiary (*see Consolidated Variable Interest Entities below*). As of March 31, 2015 and December 31, 2014, the Registrants had significant interests in seven and six other VIEs, respectively, for which the Registrants do not have the power to direct the entities' activities and, accordingly, were not the primary beneficiary.

***Consolidated Variable Interest Entities***

Exelon, Generation and BGE's consolidated VIEs consist of:

BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property,

a retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier

a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,

several wind project companies designed by Generation to develop, construct and operate wind generation facilities,

certain retail power companies for which Generation is the sole supplier of energy, and

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As of March 31, 2015 and December 31, 2014, ComEd and PECO do not have any material consolidated VIEs.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of March 31, 2015 and December 31, 2014, Exelon, Generation, and BGE provided the following support to their respective consolidated VIEs:

In the case of BondCo, BGE is required to remit all payments it receives from all residential customers through non-bypassable, rate stabilization charges to BondCo. During the three months ended March 31, 2015 and March 31, 2014, BGE remitted \$21 million and \$21 million to BondCo, respectively.

Generation provides operating and capital funding to the solar entities for ongoing construction, operations and maintenance of the solar power facilities and provides limited recourse related to the Antelope Valley project.

Generation and Exelon, where indicated, provide the following support to CENG (see Note 6 Investment in Constellation Energy Nuclear Group, LLC, and Note 25 Related Party Transactions, of the Exelon 2014 Form 10-K for additional information regarding Generation's and Exelon's transactions with CENG):

under the NOSA, Generation conducts all activities related to the operation of the CENG nuclear generation fleet owned by CENG subsidiaries (the CENG fleet) and provides corporate and administrative services for the remaining life and decommissioning of the CENG nuclear plants as if they were a part of the Generation nuclear fleet, subject to the CENG member rights of EDF Inc. (EDFI) (a subsidiary of EDF),

under the Power Services Agency Agreement (PSAA), Generation provides scheduling, asset management, and billing services to the CENG fleet for the remaining operating life of the CENG nuclear plants,

under power purchase agreements with CENG, Generation will purchase 50.01% of the available output generated by the CENG nuclear plants from January 2015 through the end of the operating life of each respective plant. However, pursuant to amendments dated March 31, 2015, the energy obligations under the Ginna Nuclear Power Plant (Ginna) PPAs have been suspended during the term of the Reliability Support Services Agreement (RSSA) which Ginna entered into with Rochester Gas and Electric Corporation (RG&E) on February 13, 2015. The obligations under the RSSA commenced on April 1, 2015 and are effective through September 30, 2018, (see Note 5 Regulatory Matters for additional details),

Generation provided a \$400 million loan to CENG. As of March 31, 2015, the remaining obligation is \$288 million, which reflects the principal payment made in January 2015 (see Note 5 Investment in Constellation Energy Nuclear Group, LLC of the Exelon 2014 Form 10-K for additional details),

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this Indemnity Agreement. (See Note 17 Commitments and Contingencies for more details),



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in connection with CENG's severance obligations, Generation has agreed to reimburse CENG for a total of approximately \$6 million of the severance benefits paid or to be paid in 2014 through 2016. As of March 31, 2015, the remaining obligation is approximately \$2 million,

Generation and EDFI share in the \$637 million of contingent payment obligations for the payment of contingent retrospective premium adjustments for the nuclear liability insurance (see Note 17 Commitments and Contingencies for more details),

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

Generation provides a guarantee of approximately \$7 million associated with hazardous waste management facilities and underground storage tanks. In addition, EDFI executed a reimbursement agreement that provides reimbursement to Exelon for 49.99% of any amounts paid by Generation under this guarantee,

Generation and EDFI are the members-insured with Nuclear Electric Insurance Limited (NEIL) and have assigned the loss benefits under the insurance and the NEIL premium costs to CENG and guarantee the obligations of CENG under these insurance programs in proportion to their respective member interests (see Note 17 Commitments and Contingencies for more details), and

Exelon has executed an agreement to provide up to \$245 million to support the operations of CENG as well as a \$165 million guarantee of CENG's cash pooling agreement with its subsidiaries.

Generation provides approximately \$7 million in credit support for the retail power companies for which Generation is the sole supplier of energy, and

Generation provides a \$75 million parental guarantee to the third-party gas supplier in support of its retail gas group. For each of the consolidated VIEs, except as otherwise noted:

the assets of the VIEs are restricted and can only be used to settle obligations of the respective VIE;

Exelon, Generation and BGE did not provide any additional material financial support to the VIEs;

Exelon, Generation and BGE did not have any material contractual commitments or obligations to provide financial support to the VIEs; and

the creditors of the VIEs did not have recourse to Exelon's, Generation's or BGE's general credit.

The carrying amounts and classification of the consolidated VIEs' assets and liabilities included in Exelon's, Generation's, and BGE's consolidated financial statements at March 31, 2015 and December 31, 2014 are as follows:

	March 31, 2015			December 31, 2014		
	Exelon <sup>(a)</sup>	Generation	BGE	Exelon <sup>(a)</sup>	Generation	BGE
Current assets	\$ 1,185	\$ 1,134	\$ 46	\$ 1,271	\$ 1,242	\$ 21
Noncurrent assets	7,676	7,664	3	7,580	7,566	3
<b>Total assets</b>	<b>\$ 8,861</b>	<b>\$ 8,798</b>	<b>\$ 49</b>	<b>\$ 8,851</b>	<b>\$ 8,808</b>	<b>\$ 24</b>

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Current liabilities	\$ 520	\$ 434	\$ 80	\$ 611	\$ 526	\$ 77
Noncurrent liabilities	2,812	2,682	120	2,730	2,600	120
Total liabilities	\$ 3,332	\$ 3,116	\$ 200	\$ 3,341	\$ 3,126	\$ 197

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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*Assets and Liabilities of Consolidated VIEs*

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of March 31, 2015 and December 31, 2014, these assets and liabilities primarily consisted of the following:

	March 31, 2015			December 31, 2014		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	\$ 334	\$ 334	\$	\$ 392	\$ 392	\$
Restricted cash	159	113	46	117	96	21
Accounts receivable, net						
Customer	296	296		297	297	
Other	33	33		57	57	
Mark-to-market derivatives assets	130	130		171	171	
Inventory						
Materials and supplies	168	168		172	172	
Other current assets	40	34		33	26	
<b>Total current assets</b>	<b>1,160</b>	<b>1,108</b>	<b>46</b>	<b>1,239</b>	<b>1,211</b>	<b>21</b>
Property, plant and equipment, net	4,720	4,720		4,638	4,638	
Nuclear decommissioning trust funds	2,114	2,114		2,097	2,097	
Goodwill	47	47		47	47	
Mark-to-market derivatives assets	51	51		44	44	
Other noncurrent assets	90	78	3	95	82	3
<b>Total noncurrent assets</b>	<b>7,022</b>	<b>7,010</b>	<b>3</b>	<b>6,921</b>	<b>6,908</b>	<b>3</b>
<b>Total assets</b>	<b>\$ 8,182</b>	<b>\$ 8,118</b>	<b>\$ 49</b>	<b>\$ 8,160</b>	<b>\$ 8,119</b>	<b>\$ 24</b>
Long-term debt due within one year	\$ 85	\$ 5	\$ 75	\$ 87	\$ 5	\$ 75
Accounts payable	268	268		292	292	
Accrued expenses	77	71	5	111	108	2
Mark-to-market derivative liabilities	10	10		24	24	
Unamortized energy contract liabilities	9	9		22	22	
Other current liabilities	18	18		25	25	
<b>Total current liabilities</b>	<b>467</b>	<b>381</b>	<b>80</b>	<b>561</b>	<b>476</b>	<b>77</b>
Long-term debt	211	81	120	212	81	120
Asset retirement obligations	1,843	1,843		1,763	1,763	
Pension obligation <sup>(a)</sup>	9	9		9	9	
Unamortized energy contract liabilities	48	48		51	51	
Other noncurrent liabilities	124	124		127	127	
<b>Noncurrent liabilities</b>	<b>2,235</b>	<b>2,105</b>	<b>120</b>	<b>2,162</b>	<b>2,031</b>	<b>120</b>

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Total liabilities	\$ 2,702	\$ 2,486	\$ 200	\$ 2,723	\$ 2,507	\$ 197
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- (a) Includes CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation s balance sheet. See Note 12 Retirement Benefits for additional details.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)*****Unconsolidated Variable Interest Entities***

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

The Registrants' unconsolidated VIEs consist of:

Energy purchase and sale agreements with VIEs for which Generation has concluded that consolidation is not required.

Asset sale agreement with ZionSolutions, LLC and EnergySolutions, Inc. in which Generation has a variable interest but has concluded that consolidation is not required.

Equity investments in energy development projects and energy generating facilities for which Generation has concluded that consolidation is not required.

As of March 31, 2015 and December 31, 2014, Exelon and Generation had significant unconsolidated variable interests in seven and six VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to the execution of an energy purchase and sale agreement with a new unconsolidated VIE. The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

	<b>Commercial Agreement VIEs</b>	<b>Equity Investment VIEs</b>	<b>Total</b>
<b>March 31, 2015</b>			
Total assets <sup>(a)</sup>	\$ 259	\$ 85	\$ 344
Total liabilities <sup>(a)</sup>	32	47	79
Exelon's ownership interest in VIE <sup>(b)</sup>		9	9
Other ownership interests in VIE <sup>(a)</sup>	227	29	256
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments		13	13
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning <sup>(b)</sup>	27		27

	<b>Commercial Agreement VIEs</b>	<b>Equity Investment VIEs</b>	<b>Total</b>
<b>December 31, 2014</b>			
Total assets <sup>(a)</sup>	\$ 506	\$ 91	\$ 597

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Total liabilities <sup>(a)</sup>	237	49	286
Exelon's ownership interest in VIE <sup>(b)</sup>		9	9
Other ownership interests in VIE <sup>(a)</sup>	269	33	302
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments		13	13
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning <sup>(b)</sup>	27		27

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- (a) These items represent amounts on the unconsolidated VIE balance sheets, not on Exelon's or Generation's Consolidated Balance Sheets. These items are included to provide information regarding the relative size of the unconsolidated VIEs.
- (b) These items represent amounts on Exelon's and Generation's Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning include, gross pledged assets of \$308 million and \$319 million as of March 31, 2015 and December 31, 2014, respectively; offset by payables to ZionSolutions, LLC of \$281 million and \$292 million as of March 31, 2015 and December 31, 2014, respectively. These items are included to provide information regarding the relative size of the ZionSolutions, LLC unconsolidated VIE.

For each of the unconsolidated VIEs, Exelon and Generation has assessed the risk of a loss equal to their maximum exposure to be remote and, accordingly, Exelon and Generation have not recognized a liability associated with any portion of the maximum exposure to loss. In addition, there are no material agreements with, or commitments by, third parties that would affect the fair value or risk of their variable interests in these VIEs.

**4. Mergers, Acquisitions, and Dispositions****Proposed Merger with Pepco Holdings, Inc. (Exelon)*****Description of Transaction***

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive \$27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased \$144 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI as of March 31, 2015, with additional investments of \$18 million to be made quarterly up to a maximum aggregate investment of \$180 million. The preferred securities are included in Other non-current assets on Exelon's Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately \$7.2 billion. As part of the applications for approval of the merger, under pending or final settlements reached to date, as well as other filings, Exelon and PHI have proposed a package to the PHI utilities' respective customers, providing for direct investment in excess of approximately \$300 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it had substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI have cooperated with the DOJ regarding the proposed merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPUB) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses.



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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the Delaware Public Service Commission (DPSC) to review the proposed merger. The settlement, which was amended on April 7, 2015 and is subject to the approval of the DPSC, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environment Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI have proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of \$40 million for DPL customers in Delaware, \$2 million of funding for energy efficiency programs for DPL low income customers, and \$2 million of funding for workforce development.

On March 17, 2015, Exelon and PHI announced that they had reached a settlement agreement with Montgomery and Prince George's Counties in the proceeding before the MDPSC to review the proposed merger. The settlement, which is subject to the approval of the MDPSC, was signed and filed by Exelon, PHI, Montgomery County, Prince George's County, the National Consumer Law Center, National Housing Trust, Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers and a consortium of recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts. As part of this settlement, Exelon and PHI have proposed a package of benefits to Potomac Electric Power Company (Pepco) and DPL customers and the state of Maryland including the establishment of a customer investment fund of \$94.4 million for utility customers in Maryland. A portion of the customer investment fund, representing approximately \$36.8 million, will provide bill credits to Pepco and DPL customers in Maryland, with the remaining \$57.6 million funding energy-efficiency programs, including programs targeted to help low income customers lower their energy bills. Exelon also agreed to establish a Green Sustainability Fund (GSF) of \$50 million to be allocated across the service territories of Pepco, DPL and ACE, with \$19.8 million allocated to Maryland. The GSF will be allocated within each state to state and local green banks and similar sponsoring organizations to make loans to finance public and private investment in renewable energy, microgrids, and other developing energy technologies. Loans made by sponsoring organizations from the GSF must mature within 20 years following the merger closing. At the end of that 20 year period, principal payments received by the sponsoring organizations must be returned to Exelon, but Exelon's recovery of the entire GSF is not assured. In the settlement, Exelon also agreed to provide \$4 million in funding for workforce development in Maryland and made various other commitments, including a commitment to develop 15 MW of commercial solar projects in Maryland. In a related agreement with Prince George's County, Exelon agreed to develop an additional 5 MW of solar generation in Maryland, the output of which will be delivered to Prince George's County under a 30-year PPA at no cost to the county for the first 15 years and at market pricing for the second 15 years. This agreement also requires Prince George's County to purchase substantially all of its requirements for electricity and natural gas from an Exelon affiliate for a period of 15 years, unless the Exelon affiliate is not the lowest bidder.

On March 10, 2015, Exelon and PHI announced that they had reached a settlement agreement with the Alliance for Solar Choice, a group of solar developers, in the proceeding before the MDPSC. The settlement, which is subject to the approval of the MDPSC, provides for enhancements to the interconnection process for behind-the-meter distributed generation and storage projects.

Exelon and PHI continue to expect the merger to be completed late in the second or third quarter of 2015.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval. Final court approval of the proposed

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Including 2014 and through March 31, 2015, Exelon has incurred approximately \$289 million of expense associated with the proposed merger, primarily \$69 million related to acquisition and integration costs and \$220 million of costs incurred to finance the transaction.

The Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from \$259 million to \$293 million plus certain expenses. If the Merger Agreement is terminated due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, through the redemption by PHI of the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock, plus certain expenses.

***Merger Financing***

Exelon intends to fund the all-cash transaction using a combination of approximately \$3.5 billion of debt, up to \$1.0 billion in cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of \$35 per share in connection with forward sales agreements and \$1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day \$7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to a \$3.2 billion facility as a result of the execution of the equity issuance and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 9 Debt and Credit Agreements and Note 15 Common Stock for more information.

**Acquisitions (Exelon and Generation)**

***Acquisition of Integrys Energy Group, Inc. (Exelon and Generation)***

On November 1, 2014, Generation acquired the competitive retail electric and natural gas business activities of Integrys Energy Group, Inc. through the purchase of all of the stock of its wholly owned subsidiary, Integrys Energy Services, Inc. (Integrys) for a purchase price of \$332 million, including net working capital. As of March 31, 2015, Generation had remitted \$319 million to Integrys Energy Group, Inc. and the remaining balance of \$13 million is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets. The remaining balance was paid on April 17, 2015.

**Asset Divestitures (Exelon and Generation)**

On January 21, 2015, Generation closed on the sale of the Quail Run generating facility. Including the sale of the Quail Run generating facility, Generation has sold generating assets for total pre-tax proceeds of \$1.8 billion (after-tax proceeds of \$1.4 billion) which are expected to be used primarily to finance a portion of the acquisition of PHI.

At March 31, 2015, assets of \$1 million related to property, plant and equipment are recorded as Assets held for sale on Exelon's and Generation's Consolidated Balance Sheet.

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

**5. Regulatory Matters (Exelon, Generation, ComEd, PECO and BGE)***Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)*

Except for the matters noted below, the disclosures set forth in Note 3 Regulatory Matters of the Exelon 2014 Form 10-K appropriately represent, in all material respects, the current status of regulatory and legislative proceedings of the Registrants. The following is an update to that discussion.

**Illinois Regulatory Matters**

**Energy Infrastructure Modernization Act (Exelon and ComEd).** Since 2011, ComEd's distribution rates are established through a performance-based rate formula, pursuant to EIMA. EIMA also provides a structure for substantial capital investment by utilities to modernize Illinois' electric utility infrastructure. EIMA was scheduled to sunset, ending ComEd's performance based rate formula and investment commitment, at December 31, 2017, unless approved to continue through 2022 by the Illinois General Assembly. On April 3, 2015, the Governor signed legislation extending the EIMA sunset from 2017 to 2019.

Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd's best estimate of the revenue requirement expected to be approved by the ICC for that year's reconciliation. As of March 31, 2015, and December 31, 2014, ComEd had recorded a net regulatory asset associated with the distribution formula rate of \$316 million and \$371 million, respectively. The regulatory asset associated with distribution true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

On April 15, 2015, ComEd filed its annual distribution formula rate with the ICC. The filing establishes the revenue requirement used to set the rates that will take effect in January 2016 after the ICC's review and approval, which is due by December 2015. The revenue requirement requested is based on 2014 actual costs plus projected 2015 capital additions as well as an annual reconciliation of the revenue requirement in effect in 2014 to the actual costs incurred that year. ComEd's 2015 filing request includes a total decrease to the revenue requirement of \$50 million, reflecting an increase of \$92 million for the initial revenue requirement for 2016 and an decrease of \$142 million related to the annual reconciliation for 2014. The revenue requirement for 2016 provides for a weighted average debt and equity return on distribution rate base of 7.05% inclusive of an allowed return on common equity of 9.14%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2014 provided for a weighted average debt and equity return on distribution rate base of 7.02% inclusive of an allowed return on common equity of 9.09%, reflecting the average rate on 30-year treasury notes plus 580 basis points less a performance metrics penalty of 5 basis points.

Participating utilities are also required to file an annual update on their AMI implementation progress. On June 11, 2014, the ICC approved ComEd's accelerated deployment plan which allows for the installation of more than four million smart meters throughout ComEd's service territory by 2018, three years in advance of the originally scheduled 2021 completion date. On April 1, 2015, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC. To date, over one million smart meters have been installed in the Chicago area.

**Grand Prairie Gateway Transmission Line (Exelon and ComEd).** On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC

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issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 were immaterial. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. On January 15, 2015, the City of Elgin and other parties filed a Notice of Appeal in the Illinois Appellate Court. On April 8, 2015, the ICC issued a rehearing order denying the appeals filed to consider an alternate route for the transmission line. The rehearing order affirmed the route approved within the ICC's October 22, 2014 order. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

**Pennsylvania Regulatory Matters**

**2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO).** On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of \$190 million to its annual service revenues for electric delivery, which would reflect a 4.4% increase on the basis of total Pennsylvania jurisdictional operating revenue. The requested rate of return on common equity is 10.95%. The new electric delivery rates would take effect no later than January 1, 2016. The results of the rate case are expected to be known in the fourth quarter of 2015. PECO cannot predict how much of the requested increase the PAPUC will ultimately approve.

**Pennsylvania Procurement Proceedings (Exelon and PECO).** On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO's second DSP Program, which was filed with the PAPUC in January 2012. The program, which has a 24-month term from June 1, 2013 through May 31, 2015, complies with electric generation procurement guidelines set forth in Act 129. In the second DSP Program, PECO entered into contracts with PAPUC-approved bidders, including Generation, to procure electric supply for its default electric customers through five competitive procurements.

In addition, the second DSP Program includes a number of retail market enhancements recommended by the PAPUC in its previously issued Retail Markets Intermediate Work Plan Order. PECO was also directed to submit a plan to allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning in April 2014. In May 2013, PECO filed its CAP Shopping Plan with the PAPUC. By Order entered on January 24, 2014, the PAPUC approved PECO's plan, with modifications, to make CAP shopping available beginning April 15, 2014. On March 20, 2014, the Office of Consumer Advocate (OCA) and low-income advocacy groups filed an appeal and emergency request for a stay with the Pennsylvania Commonwealth Court, claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On March 11, 2015, the appeal was argued before the Commonwealth Court (the Court). PECO cannot implement CAP Shopping until the Court reaches a decision, which is expected in 2015.

On December 4, 2014, the PAPUC approved PECO's third DSP Program. The program has a 24-month term from June 1, 2015 through May 31, 2017, and complies with electric generation procurement guidelines set forth in Act 129. Under the program, PECO is procuring electric supply through four competitive procurements for fixed price full requirements contracts of two years or less for the residential classes and small and medium commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In March 2015, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential class and its small, medium, and large commercial classes commencing in June 2015. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO's Statement of Operations and Comprehensive Income.

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design

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changes the rate structure of PECO's CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO's universal service fund cost. If the CAP Design proposed plan is approved by the PAPUC, PECO plans to implement the program changes in October 2016.

**Smart Meter and Smart Grid Investments (Exelon and PECO).** In April 2010, pursuant to Act 129 and the follow-on Implementation Order of 2009, the PAPUC approved PECO's Smart Meter Procurement and Installation Plan (SMPIP). PECO is currently in the second phase of the SMPIP, under which PECO will deploy substantially all remaining smart meters, for a total of 1.7 million smart meters, on an accelerated basis by the second quarter of 2015. In total, PECO currently expects to spend up to \$591 million, excluding the cost of the original meters, on its smart meter infrastructure and approximately \$155 million on smart grid investments through final deployment of which \$200 million was funded by SGIG. As of March 31, 2015, PECO has spent \$568 million and \$155 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received.

For further information on the SGIG and Smart Meter and Smart Grid program, see Note 3 Regulatory Matters of the Exelon 2014 Form 10-K.

**Pennsylvania Act 11 of 2012 (Exelon and PECO).** In February 2012, Act 11 was signed into law, which seeks to clarify the PAPUC's authority to approve alternative ratemaking mechanisms, allowing 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. Prior to recovering costs pursuant to a DSIC, the PAPUC's implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure.

On February 5, 2015, PECO filed a petition to modify its natural gas LTIIIP with the PAPUC, which was originally approved by the PAPUC in May 2013. If approved, the modification would allow PECO to further accelerate the replacement of existing gas mains and also included a plan for the relocation of meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas LTIIIP expenditures.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIIP. In accordance with the LTIIIP (System 2020 plan), PECO plans to spend \$275 million over the next five years to modernize and storm-harden its electric distribution system, making it more weather resistant and less vulnerable to damage. If approved, the DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases.

**Maryland Regulatory Matters**

**2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE).** On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately requesting increases of \$83 million and \$24 million, respectively. In addition to these requested rate increases, BGE's application included a request for recovery of incremental capital expenditures and operating costs associated with BGE's proposed short-term reliability improvement plan (the ERI initiative) in response to a MDPSC order through a surcharge separate from base rates.

On December 13, 2013, the MDPSC issued an order in BGE's 2013 electric and natural gas distribution rate case for increases in annual distribution service revenue of \$34 million and \$12 million, respectively, and an allowed return on equity of 9.75% and 9.60%, respectively. Rates became effective for services rendered on or

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after December 13, 2013. The MDPSC also authorized BGE to recover through a surcharge mechanism costs associated with five ERI initiative programs designed to accelerate electric reliability improvements premised upon the condition that the MDPSC approve specific projects in advance of cost recovery. On March 31, 2014, after reviewing comments filed by the parties and conducting a hearing on the matter, the MDPSC approved all but one project proposed for completion in 2014 as part of the ERI initiative. The ERI initiative surcharge became effective June 1, 2014. On November 3, 2014, BGE filed a surcharge update including a true-up of cost estimates included in the 2014 surcharge, along with its work plan and cost estimates for 2015, to be included in the 2015 surcharge. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2014 annual report, 2015 work plan and the 2015 surcharge.

In January 2014, the residential consumer advocate in Maryland filed an appeal to the order issued by the MDPSC on December 13, 2013 in BGE's 2013 electric and gas distribution rate cases. The residential consumer advocate filed its related legal memorandum on August 22, 2014, challenging the MDPSC's approval of the ERI initiative surcharge. BGE submitted a response to the appeal on October 15, 2014, and a hearing was held on November 17, 2014. BGE cannot predict the outcome of this appeal. If the residential consumer advocate's appeal is successful, BGE could recover ERI expenditures through other regulatory mechanisms.

**Smart Meter and Smart Grid Investments (Exelon and BGE).** In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that included the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of \$480 million of which \$200 million was recovered through a grant from the DOE. The MDPSC's approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of March 31, 2015 and December 31, 2014, BGE recorded a regulatory asset of \$143 million and \$128 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE's 2014 electric and gas distribution rate case, the cost of the retired non-AMI meters will be amortized over 10 years.

**The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE).** In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to recover promptly reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the Maryland PSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of cost estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015. As of March 31, 2015, BGE recorded a regulatory liability of \$1 million, representing the difference between the surcharge revenues and program costs.

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In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSB on BGE's infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSB decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. The Court of Special Appeals has issued a preliminary procedural schedule that sets oral argument in this matter for a date in the first two weeks of November 2015.

**New York Regulatory Matters**

***Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation).*** Ginna Nuclear Power Plant's (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the agreement, Ginna advised the New York Public Service Commission (NYPSB) and ISO-NY that in absence of a reliability need, Ginna management would make a recommendation, subject to approval by the CENG board, that Ginna be retired as soon as practicable. A formal study conducted by the ISO-NY and RG&E concluded that the Ginna nuclear plant needs to remain in operation to maintain the reliability of the transmission grid in the Rochester region through 2018 when planned transmission system upgrades are expected to be completed. In November 2014, in response to a petition filed by Ginna, the NYPSB directed Ginna and RG&E to negotiate a Reliability Support Services Agreement (RSSA). On February 13, 2015, regulatory filings, including RSSA terms negotiated between Ginna and RG&E, to support the continued operation of Ginna for reliability purposes were made with the NYPSB and with FERC for their approval. Although the RSSA contract is still subject to regulatory approvals, on April 1, 2015, Ginna began delivering power and capacity into ISO-NY consistent with the provisions of the proposed RSSA contract. RG&E may terminate the RSSA contract upon providing 12-months' notice, which would require RG&E to make a specified termination payment to Ginna. The proposed RSSA contract extends through September 30, 2018. In the event that Ginna continues to operate beyond the RSSA term, Ginna would be required to make a specified refund payment to RG&E. The FERC issued an order on April 14, 2015, directing Ginna to make a compliance filing to ensure that the RSSA does not allow Ginna to receive revenues above its full cost-of-service and rejecting any extension of the RSSA beyond its initial term, rather requiring any extension be subject to the rules currently being developed by ISO-NY. The FERC order also set the RSSA for hearing and settlement procedures. Until final regulatory approvals are received, Generation will recognize revenue based on market prices for energy and capacity delivered by Ginna into ISO-NY. Upon receiving regulatory approvals, under the RSSA contract terms, Generation would record an adjustment to recognize revenue based on the final approved pricing contained in the contract as of the April 1, 2015 effective date. While the RSSA is expected to receive regulatory approvals and, therefore, permit Ginna to continue operating through the RSSA term, there is still a risk that, for economic reasons, including adjustments to the revenue Ginna would be entitled to under the RSSA, Ginna could be retired before the end of its operating license period. In absence of such an agreement and in the event the plant is retired before the current license term ends in 2029, Exelon's and Generation's results of operations could be adversely affected by increased depreciation rates, impairment charges, severance costs, and accelerated future decommissioning costs, among other items. However, it is not expected that such impacts would be material to Exelon's or Generation's results of operations.

**Federal Regulatory Matters**

***Transmission Formula Rate (Exelon, ComEd and BGE).*** ComEd's and BGE's transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd's and BGE's best estimate of the revenue requirement expected to be approved by the FERC for that year's reconciliation. As of March 31, 2015 and December 31, 2014, ComEd had recorded a net regulatory asset associated with the transmission formula rate of \$25 million and \$21 million, respectively, and BGE recorded a net regulatory asset associated with the transmission formula rate of \$2 million and \$1 million at March 31, 2015 and December 31, 2014, respectively. The regulatory asset associated with the transmission true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

On April 15, 2015, ComEd filed its annual transmission formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that will take effect in June 2015, subject to review by the FERC and other parties, which is due by October 2015. ComEd's 2015 filing request includes a total increase to the revenue requirement of \$91 million, reflecting an increase of \$73 million for the initial revenue requirement and an increase of \$18 million related to the annual reconciliation. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.61%, inclusive of an allowed return on common equity of 11.50%, a decrease from the 8.62% average debt and equity return previously authorized.

As part of the FERC-approved settlement of ComEd's 2007 transmission rate case, the rate of return on common equity is 11.50% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the transmission formula rate is currently capped at 55%.

In April 2015, BGE filed its annual transmission formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that will take effect in June 2015, subject to review by the FERC and other parties, which is due by October 2015. BGE's 2015 filing request includes a total increase to the revenue requirement of \$10 million, reflecting an increase of \$13 million for the initial revenue requirement and a decrease of \$3 million related to the annual reconciliation. The revenue requirement provides for a weighted average debt and equity return on transmission rate base of 8.46%, inclusive of an allowed return on common equity of 11.30%, a decrease from the 8.53% average debt and equity return previously authorized.

As part of the FERC-approved settlement of BGE's 2005 transmission rate case in 2006, the rate of return on common equity for BGE's electric transmission business for new transmission projects placed in service on and after January 1, 2006 is 11.30%, which is inclusive of a 50 basis point incentive for participating in PJM.

***FERC Transmission Complaint (Exelon and BGE).*** On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016. On March 2, 2015, the Presiding Administrative Law Judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately \$11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately \$13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately \$14 million.

***PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE).*** PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. 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. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit.

In August 2009, the court issued its decision affirming the FERC's order with regard to the existing facilities, but remanded to FERC the issue of the cost allocation associated with the new facilities 500 kV and above (Cost Allocation Issue) for further consideration by the FERC. On remand, FERC reaffirmed its earlier decision to socialize the costs of new facilities 500 kV and above. A number of parties filed appeals of these orders. In June 2014, the court again remanded the Cost Allocation Issue to FERC. On December 18, 2014, FERC issued an order setting an evidentiary hearing and settlement proceeding regarding the Cost Allocation Issue. The hearing only concerns new facilities approved by the PJM Board prior to February 1, 2013. As of March 31, 2015, settlement discussions are continuing.

Because a new cost allocation had been adopted for projects approved by the PJM Board on or after February 1, 2013, this latest remand only involves the cost allocation for facilities 500 kV and above approved prior

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to that date. ComEd anticipates that all impacts of any rate design changes effective after December 31, 2006, should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on ComEd's results of operations, cash flows or financial position. PECO anticipates that all impacts of any rate design changes should be recoverable through the transmission service charge rider approved in PECO's 2010 electric distribution rate case settlement and, thus, the rate design changes are not expected to have a material impact on PECO's results of operations, cash flows or financial position. To the extent any rate design changes are retroactive to periods prior to January 1, 2011, there may be an impact on PECO's results of operations. BGE anticipates that all impacts of any rate design changes effective after the implementation of its standard offer service programs in Maryland should be recoverable through retail rates and, thus, the rate design changes are not expected to have a material impact on BGE's results of operations, cash flows or financial position.

***Demand Response Resource Order (Exelon, Generation, ComEd, PECO, BGE).*** On May 23, 2014, the D.C. Circuit Court issued an opinion vacating the FERC Order No. 745 (D.C. Circuit Decision). Order No. 745 established uniform compensation levels for demand response resources that participate in the day ahead and real-time wholesale energy markets. Under Order No. 745, buyers in ISO and RTO markets were required to pay demand response resources the full Locational Marginal Price when the demand response replaced a generation resource and was cost-effective.

In addition to invalidating the compensation structure established by Order No. 745, the D.C. Circuit Court, in broad language, explained that demand response is part of the retail market and FERC is restricted from regulating retail markets. The full implication of the D.C. Circuit Decision for both energy and capacity markets regulated by FERC is not yet known and will depend on how FERC and the RTOs and ISOs implement the decision. FERC and several other parties sought rehearing of the D.C. Circuit Decision, which was denied in September 2014. In addition, on September 22, 2014, FERC and another party sought to stay the issuance of the D.C. Circuit Court's mandate so that FERC may appeal the decision to the U.S. Supreme Court. The stay was granted with respect to the FERC's request only. In January 2015, the FERC sought to appeal the decision to the U.S. Supreme Court. Thus, the stay will be extended at least until the U.S. Supreme Court determines whether to allow the appeal. In addition, contemporaneously with the D.C. Circuit Court's decision on May 23, 2014, First Energy filed a complaint at FERC asking FERC to direct PJM to remove all PJM Tariff provisions that allow or require PJM to compensate demand response providers as a form of supply in the PJM capacity market effective May 23, 2014. FirstEnergy also asked FERC to declare the results of PJM's May 2014 Base Residual Auction for the 2017/2018 Delivery Year, void and illegal to the extent that demand response resources cleared that auction. On November 14, 2014, the New England Power Generators Association, Inc. (NEPGA) filed a similar complaint at FERC asking FERC to disqualify demand response from the upcoming capacity auction in New England and to revise the New England tariff to remove demand response from participation in the capacity market. FERC's response to the FirstEnergy complaint and the NEPGA complaint and its response to address the D.C. Circuit Court's decision in all markets could preclude demand response resources from receiving any future capacity market revenues and also subject such resources to refund obligations. In addition, there is uncertainty as to how FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation resources. FERC could grant all or a portion of the relief requested by FirstEnergy and may grant relief retroactively or only prospectively. FERC could also pursue alternative means for allowing demand response to effectively participate in capacity markets it regulates. Due to these uncertainties, the Registrants are unable to predict the outcome of these proceedings, and the final outcome is not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE's results of operations and cash flows.

***New England Capacity Market Results (Exelon and Generation).*** Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation

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regarding the competitiveness of the auction. Consistent with this requirement, on February 27, 2015, ISO-NE filed the results of its ninth capacity auction (covering the June 1, 2018 through May 30, 2019 delivery period).

On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 30, 2018 delivery period). On June 27, 2014, the FERC issued a letter to ISO-NE noting that ISO-NE's February 28, 2014 filing was deficient and that ISO-NE must file additional information before the FERC can process the filing. ISO-NE filed the information on July 17, 2014, and the ISO-NE's filings became effective by operation of law pursuant to a notice issued by the secretary of FERC on September 16, 2014. Several parties sought rehearing of the secretary's notice which was effectively denied in October 2014 and have since appealed the matter to the D.C. Circuit Court. On April 7, 2015 the D.C. Circuit Court issued an order referring the matter to a merits panel where issues raised by parties challenging the FERC decision will be heard as well as FERC's Motion to Dismiss the challenges. It is not clear whether the court will decide ultimately on the merits of the case or whether it will dismiss the case as FERC urges based on the fact that there is no action by the FERC to be considered. Nonetheless, while any change in the auction results is thought to be unlikely, Exelon and Generation cannot predict with certainty what further action the court may take concerning the results of that auction, but any court action could be material to Exelon's and Generation's expected revenues from the capacity auction.

***License Renewals (Exelon and Generation).*** On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Project (Muddy Run), respectively.

Generation is working with stakeholders to resolve water quality licensing issues with the MDE for Conowingo, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. On January 30, 2014, Generation filed a water quality certification application pursuant to Section 401 of the CWA with MDE for Conowingo, addressing these and other issues, although Generation cannot currently predict the conditions that ultimately may be imposed. MDE indicated that it believed it did not have sufficient information to process Generation's application. As a result, on December 5, 2014, Generation withdrew its pending application for a water quality certification. FERC policy requires that an applicant resubmit its request for a water quality certification within 90 days of the date of withdrawal. Accordingly, on March 3, 2015, Generation refiled its application for a water quality certification. In addition, Generation has entered into an agreement with MDE to work with state agencies in Maryland, the U.S. Army Corps of Engineers, the U.S. Geological Survey, the University of Maryland Center for Environmental Science and the U.S. Environmental Protection Agency Chesapeake Bay Program to design, conduct and fund an additional multi-year sediment study. Generation has agreed to contribute up to \$3.5 million to fund the additional study. Resolution of these issues relating to Conowingo may have a material effect on Exelon's and Generation's results of operations and financial position through an increase in capital expenditures and operating costs.

On June 3, 2014, and subsequently modified December 9, 2014, the PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. On March 2, 2015, Generation and US Fish and Wildlife Services (USFWS) submitted to FERC an executed settlement agreement resolving all outstanding issues related to Muddy Run. The financial impact associated with these commitments is estimated to be in the range of \$25 million to \$35 million, and will include both capital expenditures and operating expenses, primarily relating to fish passage and habitat improvement projects.

The FERC licenses for Muddy Run and Conowingo expired on August 31, 2014 and September 1, 2014 respectively. Under the Federal Power Act, FERC is required to issue annual licenses for the facilities until the new licenses are issued. On September 10, 2014, FERC issued annual licenses for Conowingo and Muddy Run, effective as of the expiration of the previous licenses. If FERC does not issue new licenses prior to the expiration of annual licenses, the annual licenses will renew automatically. On March 11, 2015, FERC issued the final Environmental Impact Statement for Muddy Run and Conowingo.

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The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of March 31, 2015, \$40 million of direct costs associated with licensing efforts have been capitalized

**Regulatory Assets and Liabilities (Exelon, ComEd, PECO and BGE)**

Exelon, ComEd, PECO and BGE each 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.

The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of March 31, 2015 and December 31, 2014. For additional information on the specific regulatory assets and liabilities, refer to Note 3 Regulatory Matters of the Exelon 2014 Form 10-K.

<b>March 31, 2015</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
<b>Regulatory assets</b>				
Pension and other postretirement benefits	\$ 3,248	\$	\$	\$
Deferred income taxes	1,561	65	1,419	77
AMI programs	325	106	76	143
Under-recovered distribution service costs <sup>(a)</sup>	316	316		
Debt costs	54	51	3	8
Fair value of BGE long-term debt	184			
Severance	11			11
Asset retirement obligations	119	75	26	18
MGP remediation costs	250	213	36	1
Under-recovered uncollectible accounts	62	62		
Renewable energy	241	241		
Energy and transmission programs <sup>(b) (c)</sup>	41	37		4
Deferred storm costs	3			3
Electric generation-related regulatory asset	28			28
Rate stabilization deferral	136			136
Energy efficiency and demand response programs	230			230
Merger integration costs	8			8
Conservation voltage reduction	2			2
Other	53	17	24	9
<b>Total regulatory assets</b>	<b>6,872</b>	<b>1,183</b>	<b>1,584</b>	<b>678</b>
Less: current portion	804	317	41	187
<b>Total noncurrent regulatory assets</b>	<b>\$ 6,068</b>	<b>\$ 866</b>	<b>\$ 1,543</b>	<b>\$ 491</b>

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

<b>March 31, 2015</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
<b>Regulatory liabilities</b>				
Other postretirement benefits	\$ 72	\$	\$	\$
Nuclear decommissioning	2,920	2,420	500	
Removal costs	1,567	1,351		216
Energy efficiency and demand response programs	27	25	2	
DLC Program Costs	10		10	
Energy efficiency Phase 2	38		38	
Electric distribution tax repairs	106		106	
Gas distribution tax repairs	34		34	
Energy and transmission programs <sup>(b)(c)(d)</sup>	142	23	84	35
Over-recovered electric universal service fund costs	3		3	
Revenue subject to refund	3	3		
Over-recovered revenue decoupling <sup>(e)</sup>	56			56
Other	9	1	4	4
<b>Total regulatory liabilities</b>	<b>4,987</b>	<b>3,823</b>	<b>781</b>	<b>311</b>
Less: current portion	421	131	119	124
<b>Total noncurrent regulatory liabilities</b>	<b>\$ 4,566</b>	<b>\$ 3,692</b>	<b>\$ 662</b>	<b>\$ 187</b>

<b>December 31, 2014</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
<b>Regulatory assets</b>				
Pension and other postretirement benefits	\$ 3,256	\$	\$	\$
Deferred income taxes	1,542	64	1,400	78
AMI programs	296	91	77	128
Under-recovered distribution service costs <sup>(a)</sup>	371	371		
Debt costs	57	53	4	9
Fair value of BGE long-term debt	190			
Severance	12			12
Asset retirement obligations	116	74	26	16
MGP remediation costs	257	219	37	1
Under-recovered uncollectible accounts	67	67		
Renewable energy	207	207		
Energy and transmission programs <sup>(b)(c)</sup>	48	33		15
Deferred storm costs	3			3
Electric generation-related regulatory asset	30			30
Rate stabilization deferral	160			160
Energy efficiency and demand response programs	248			248
Merger integration costs	8			8
Conservation voltage reduction	2			2
Under recovered electric revenue decoupling	7			7
Other	46	22	14	7
<b>Total regulatory assets</b>	<b>6,923</b>	<b>1,201</b>	<b>1,558</b>	<b>724</b>
Less: current portion	847	349	29	214

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Total noncurrent regulatory assets	\$ 6,076	\$ 852	\$ 1,529	\$ 510
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(Dollars in millions, except per share data, unless otherwise noted)

December 31, 2014	Exelon	ComEd	PECO	BGE
<b>Regulatory liabilities</b>				
Other postretirement benefits	\$ 88	\$	\$	\$
Nuclear decommissioning	2,879	2,389	490	
Removal costs	1,566	1,343		223
Energy efficiency and demand response programs	27	25	2	
DLC Program Costs	10		10	
Energy efficiency phase II	32		32	
Electric distribution tax repairs	102		102	
Gas distribution tax repairs	49		49	
Energy and transmission programs <sup>(b)(c)(d)</sup>	84	19	58	7
Over-recovered electric universal service fund costs	2		2	
Revenue subject to refund	3	3		
Over-recovered revenue decoupling <sup>(e)</sup>	12			12
Other	6	1	2	2
<b>Total regulatory liabilities</b>	<b>4,860</b>	<b>3,780</b>	<b>747</b>	<b>244</b>
Less: current portion	310	125	90	44
<b>Total noncurrent regulatory liabilities</b>	<b>\$ 4,550</b>	<b>\$ 3,655</b>	<b>\$ 657</b>	<b>\$ 200</b>

- (a) As of March 31, 2015, ComEd's regulatory asset of \$316 million was comprised of \$240 million for the applicable annual reconciliations and \$76 million related to significant one-time events including \$59 million of deferred storm costs and \$17 million of Constellation merger and integration related costs. As of December 31, 2014, ComEd's regulatory asset of \$371 million was comprised of \$286 million for the applicable annual reconciliations and \$85 million related to significant one-time events, including \$66 million of deferred storm costs and \$19 million of Constellation merger and integration related costs. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for further information.
- (b) As of March 31, 2015, ComEd's regulatory asset of \$37 million included \$5 million related to under-recovered energy costs for non-hourly customers, \$25 million associated with transmission costs recoverable through its FERC approved formulate rate, and \$7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of March 31, 2015, ComEd's regulatory liability of \$23 million included \$5 million related to over-recovered energy costs for hourly customers and \$18 million associated with revenues received for renewable energy requirements. As of December 31, 2014, ComEd's regulatory asset of \$33 million included \$4 million related to under-recovered energy costs for non-hourly customers, \$22 million associated with transmission costs recoverable through its FERC approved formulate rate, and \$7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd's regulatory liability of \$19 million included \$3 million related to over-recovered energy costs for hourly customers and \$16 million associated with revenues received for renewable energy requirements.
- (c) As of March 31, 2015, BGE's regulatory asset of \$4 million included \$4 million of Constellation merger and integration costs and \$1 million of abandonment costs to be recovered upon FERC approval, partially offset by \$1 million related to over-recovered electric energy costs. As of March 31, 2015, BGE's regulatory liability of \$35 million related to \$31 million of over-recovered natural gas supply costs and \$4 million of over-recovered electric energy costs. As of December 31, 2014, BGE's regulatory asset of \$15 million included \$10 million related to under-recovered electric energy costs, \$4 million of Constellation merger and integration costs and \$1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE's regulatory liability of \$7 million related to over-recovered natural gas supply costs.
- (d) At PECO, includes \$42 million related to the DSP program, \$34 million related to the over-recovered natural gas costs under the PGC and \$8 million related to over-recovered electric transmission costs as of March 31, 2015. As of December 31, 2014, includes \$39 million related to the DSP program, \$16 million related to the over-recovered electric transmission costs and \$3 million related to the over-recovered natural gas costs under the PGC.

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- (e) Represents the electric and gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of March 31, 2015, BGE had a regulatory liability of \$19 million related to over-recovered electric revenue decoupling and a regulatory liability of \$37 million related to over-recovered natural gas revenue decoupling. As of December 31, 2014, BGE had a regulatory asset of \$7 million related to under-recovered electric revenue decoupling and a regulatory liability of \$12 million related to over-recovered natural gas revenue decoupling.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)**

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers that participate in the utilities' consolidated billing. ComEd and BGE purchase receivables at a discount to recover primarily uncollectible accounts expense from the suppliers. PECO is required to purchase receivables at face value and permitted to recover uncollectible accounts expense from customers through its distribution rates. Exelon, ComEd, PECO and BGE do not record unbilled commodity receivables under the POR programs. Purchased billed receivables are classified in Other accounts receivable, net on Exelon's, ComEd's, PECO's and BGE's Consolidated Balance Sheets. The following tables provide information about the purchased receivables of the Registrants as of March 31, 2015 and December 31, 2014.

<b>As of March 31, 2015</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
Purchased receivables <sup>(a)</sup>	\$ 336	\$ 150	\$ 91	\$ 95
Allowance for uncollectible accounts <sup>(b)</sup>	(51)	(25)	(10)	(16)
<b>Purchased receivables, net</b>	<b>\$ 285</b>	<b>\$ 125</b>	<b>\$ 81</b>	<b>\$ 79</b>

<b>As of December 31, 2014</b>	<b>Exelon</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
Purchased receivables <sup>(a)</sup>	\$ 290	\$ 139	\$ 76	\$ 75
Allowance for uncollectible accounts <sup>(b)</sup>	(42)	(21)	(8)	(13)
<b>Purchased receivables, net</b>	<b>\$ 248</b>	<b>\$ 118</b>	<b>\$ 68</b>	<b>\$ 62</b>

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

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

**6. Investment in Constellation Energy Nuclear Group, LLC (Exelon and Generation)**

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG, a nuclear generation business. Generation has historically had various agreements with CENG to purchase power and to provide certain services. For further information regarding these agreements, see Note 25 Related Party Transactions of the Exelon 2014 Form 10-K.

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon's and Generation's Consolidated Financial Statements between CENG and Exelon's affiliates that are considered related party transactions to Generation. As further described in Note 25 Related Party Transactions of the Exelon 2014 Form 10-K, EDF and Generation had a PPA with CENG under which they purchased 15% and 85% (through December 31, 2014), respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, sales to Generation are eliminated in consolidation. For the three months ended March 31, 2015, Generation had sales to EDF of \$182 million. See discussion above and Note 3 Variable Interest Entities for additional information regarding other transactions between CENG and EDF.

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included within Exelon and Generation s financial statements and for additional information about the Registrants VIEs.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*Accounting for the Consolidation of CENG*

For the three months ended March 31, 2014, Generation recorded \$19 million of equity in earnings of unconsolidated affiliates related to its investment in CENG and \$17 million of revenues from CENG. The book value of Generation's investment in CENG prior to the consolidation was \$1.9 billion, and the book value of the AOCI related to CENG prior to consolidation was \$116 million, net of taxes of \$77 million.

The transfer of the nuclear operating licenses and the execution of the NOSA on April 1, 2014, resulted in the derecognition of the equity method investment in CENG and the recording of all assets, liabilities and EDF's noncontrolling interest in CENG at fair value on Exelon's and Generation's Consolidated Balance Sheets.

Generation and EDFI also entered into a Put Option Agreement on April 1, 2014, pursuant to which EDFI has the option, exercisable beginning on January 1, 2016 and thereafter until June 30, 2022, to sell its 49.99% interest in CENG to Generation for a fair market value price determined by agreement of the parties, or absent agreement, a third-party arbitration process. The appraisers determining fair market value of EDF's 49.99% interest in CENG under the Put Option Agreement are instructed to take into account all rights and obligations under the CENG Operating Agreement, including Generation's rights with respect to any unpaid aggregate preferred distributions and the related return, and the value of Generation's rights to other distributions. The beginning of the exercise period will be accelerated if Exelon's affiliates cease to own a majority of CENG and exercise a related right to terminate the NOSA. In addition, under limited circumstances, the period for exercise of the put option may be extended for 18 months.

Due to the Preferred Distribution Rights that Generation has on CENG's available cash, the earnings attributable to the noncontrolling interest on the Statements of Operations and Comprehensive Income as well as the corresponding adjustment to Noncontrolling interest on the Consolidated Balance Sheets will not be in proportion to Generation's and EDF's equity ownership interests. Rather, the attribution will consider Generation's Preferred Distribution Rights and allocate net income based on each owner's rights to CENG's net assets. For the three months ended March 31, 2015, Generation reduced by \$4 million the amount of Net income attributable to noncontrolling interests on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. As a result of the consolidation, Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income includes CENG's incremental operating revenues of \$197 million and CENG's net income, prior to any intercompany eliminations and any adjustments for noncontrolling interest, of \$98 million during the three months ended March 31, 2015.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**7. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)***Fair Value of Financial Liabilities Recorded at the Carrying Amount*

The following tables present the carrying amounts and fair values of the Registrants' short-term liabilities, long-term debt, SNF obligation, and trust preferred securities (long-term debt to financing trusts or junior subordinated debentures) as of March 31, 2015 and December 31, 2014:

*Exelon*

	Carrying Amount	March 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 312	\$ 3	\$ 309	\$	\$ 312
Long-term debt (including amounts due within one year)	21,779	1,119	21,486	1,380	23,985
Long-term debt to financing trusts	648			672	672
SNF obligation	1,021		843		843

	Carrying Amount	December 31, 2014 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 463	\$ 3	\$ 448	\$ 12	\$ 463
Long-term debt (including amounts due within one year)	21,164	1,208	20,417	1,311	22,936
Long-term debt to financing trusts	648			648	648
SNF obligation	1,021		833		833

*Generation*

	Carrying Amount	March 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 25	\$	\$ 25	\$	\$ 25
Long-term debt (including amounts due within one year)	8,492		7,885	1,380	9,265
SNF obligation	1,021		843		843

	Carrying Amount	December 31, 2014 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 36	\$	\$ 24	\$ 12	\$ 36
Long-term debt (including amounts due within one year)	8,266		7,511	1,311	8,822
SNF obligation	1,021		833		833

*ComEd*

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	Carrying Amount	March 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 283	\$	\$ 283	\$	\$ 283
Long-term debt (including amounts due within one year)	6,359		7,347		7,347
Long-term debt to financing trust	206			206	206

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

	Carrying Amount	December 31, 2014 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 304	\$	\$ 304	\$	\$ 304
Long-term debt (including amounts due within one year)	5,958		6,788		6,788
Long-term debt to financing trust <i>PECO</i>	206			213	213

	Carrying Amount	March 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year)	\$ 2,246	\$	\$ 2,602	\$	\$ 2,602
Long-term debt to financing trusts	184			201	201

	Carrying Amount	December 31, 2014 Fair Value			Total
		Level 1	Level 2	Level 3	
Long-term debt (including amounts due within one year)	\$ 2,246	\$	\$ 2,537	\$	\$ 2,537
Long-term debt to financing trusts <i>BGE</i>	184			199	199

	Carrying Amount	March 31, 2015 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 3	\$ 3	\$	\$	\$ 3
Long-term debt (including amounts due within one year)	1,942		2,234		2,234
Long-term debt to financing trusts	258			265	265

	Carrying Amount	December 31, 2014 Fair Value			Total
		Level 1	Level 2	Level 3	
Short-term liabilities	\$ 123	\$ 3	\$ 120	\$	\$ 123
Long-term debt (including amounts due within one year)	1,942		2,178		2,178
Long-term debt to financing trusts	258			236	236

*Short-Term Liabilities.* The short-term liabilities included in the tables above are comprised of dividends payable (included in other current liabilities) (Level 1), short-term borrowings (Level 2) and third party financing (Level 3). The Registrants' carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments.

*Long-Term Debt.* The fair value amounts of Exelon's taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants' debt maturity spectrum. The credit spreads of various



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. The fair value of Exelon's equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

The fair value of Generation's non-government-backed fixed rate project financing debt, including nuclear fuel procurement contracts, (Level 3) is based on market and quoted prices for its own and other project financing debt with similar risk profiles. Given the low trading volume in the project financing debt market, the price quotes used to determine fair value will reflect certain qualitative factors, such as market conditions, investor demand, new developments that might significantly impact the project cash flows or off-taker credit, and other circumstances related to the project (e.g., political and regulatory environment). The fair value of Generation's government-backed fixed rate project financing debt (Level 3) is largely based on a discounted cash flow methodology that is similar to the taxable debt securities methodology described above. Due to the lack of market trading data on similar debt, the discount rates are derived based on the original loan interest rate spread to the applicable Treasury rate as well as a current market curve derived from government-backed securities. Variable rate project financing debt resets on a quarterly basis and the carrying value approximates fair value (Level 2).

*SNF Obligation.* The carrying amount of Generation's SNF obligation (Level 2) is derived from a contract with the DOE to provide for disposal of SNF from Generation's nuclear generating stations. When determining the fair value of the obligation, the future carrying amount of the SNF obligation estimated to be settled in 2025 is calculated by compounding the current book value of the SNF obligation at the 13-week Treasury rate. The compounded obligation amount is discounted back to present value using Generation's discount rate, which is calculated using the same methodology as described above for the taxable debt securities, and an estimated maturity date of 2025.

*Long-Term Debt to Financing Trusts.* Exelon's long-term debt to financing trusts is valued based on publicly traded securities issued by the financing trusts. Due to low trading volume of these securities, qualitative factors, such as market conditions, investor demand, and circumstances related to each issue, this debt is classified as Level 3.

***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.

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.

Level 3 unobservable inputs, such as internally developed pricing models or third-party valuations for the asset or liability due to little or no market activity for the asset or liability.

Transfers in and out of levels are recognized as of the end of the reporting period when 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 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were





**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

no transfers between Level 1 and Level 2 during the three months ended March 31, 2015 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

*Exelon and Generation*

The following tables present assets and liabilities measured and recorded at fair value on Exelon's and Generation's Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2015 and December 31, 2014:

As of March 31, 2015	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>								
Cash equivalents <sup>(a)</sup>	\$ 220	\$	\$	\$ 220	\$ 1,107	\$	\$	\$ 1,107
Nuclear decommissioning trust fund investments								
Cash equivalents	224	40		264	224	40		264
Equity								
Domestic	2,459	2,227		4,686	2,459	2,227		4,686
Foreign	639			639	639			639
Equity funds subtotal	3,098	2,227		5,325	3,098	2,227		5,325
Fixed income								
Corporate debt		1,911	248	2,159		1,911	248	2,159
U.S. Treasury and agencies	1,201			1,201	1,201			1,201
Foreign governments		89		89		89		89
State and municipal debt		423		423		423		423
Other		488		488		488		488
Fixed income subtotal	1,201	2,911	248	4,360	1,201	2,911	248	4,360
Middle market lending								
Private Equity			363	363			363	363
Real Estate			9	9			9	9
Other		323		323		323		323
Nuclear decommissioning trust fund investments subtotal <sup>(b)</sup>	4,523	5,501	715	10,739	4,523	5,501	715	10,739
Pledged assets for Zion Station decommissioning								
Cash equivalents		19		19		19		19
Equities	6	1		7	6	1		7
Fixed income								
U.S. Treasury and agencies	2	3		5	2	3		5
Corporate debt		84		84		84		84
State and municipal debt		10		10		10		10
Other		4		4		4		4
Fixed income subtotal	2	101		103	2	101		103
Middle market lending			178	178			178	178
Pledged assets for Zion Station decommissioning subtotal <sup>(c)</sup>	8	121	178	307	8	121	178	307

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Rabbi trust investments in mutual funds <sup>(d)(e)</sup>	16		16	48			48	
<b>Commodity derivative assets</b>								
Economic hedges	1,510	3,554	1,917	6,981	1,510	3,554	1,917	6,981
Proprietary trading	176	286	39	501	176	286	39	501
Effect of netting and allocation of collateral <sup>(f)</sup>	(1,899)	(2,849)	(740)	(5,488)	(1,899)	(2,849)	(740)	(5,488)
<b>Commodity derivative assets subtotal</b>	<b>(213)</b>	<b>991</b>	<b>1,216</b>	<b>1,994</b>	<b>(213)</b>	<b>991</b>	<b>1,216</b>	<b>1,994</b>
<b>Interest rate and foreign currency derivative assets</b>								
<b>Derivatives designated as hedging instruments</b>						32		32
Economic hedges		27		27		29		29
Proprietary trading	18	1		19	18	1		19
Effect of netting and allocation of collateral	(8)	(5)		(13)	(8)	(36)		(44)
<b>Interest rate and foreign currency derivative assets subtotal</b>	<b>10</b>	<b>23</b>		<b>33</b>	<b>10</b>	<b>26</b>		<b>36</b>
Other investments			3	3	2		3	5
<b>Total assets</b>	<b>4,564</b>	<b>6,636</b>	<b>2,112</b>	<b>13,312</b>	<b>5,485</b>	<b>6,639</b>	<b>2,112</b>	<b>14,236</b>

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of March 31, 2015	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Liabilities</b>								
Commodity derivative liabilities								
Economic hedges	(2,126)	(3,370)	(1,025)	(6,521)	(2,126)	(3,370)	(1,266)	(6,762)
Proprietary trading	(169)	(295)	(50)	(514)	(169)	(295)	(50)	(514)
Effect of netting and allocation of collateral <sup>(f)</sup>	2,324	3,585	925	6,834	2,324	3,585	925	6,834
Commodity derivative liabilities subtotal	29	(80)	(150)	(201)	29	(80)	(391)	(442)
Interest rate and foreign currency derivative liabilities								
Derivatives designated as hedging instruments		(17)		(17)		(17)		(17)
Economic hedges		(6)		(6)		(186)		(186)
Proprietary trading	(1)	(14)		(15)	(1)	(14)		(15)
Effect of netting and allocation of collateral	15	6		21	15	37		52
Interest rate and foreign currency derivative liabilities subtotal	14	(31)		(17)	14	(180)		(166)
Deferred compensation obligation		(30)		(30)		(103)		(103)
<b>Total liabilities</b>	43	(141)	(150)	(248)	43	(363)	(391)	(711)
<b>Total net assets</b>	\$ 4,607	\$ 6,495	\$ 1,962	\$ 13,064	\$ 5,528	\$ 6,276	\$ 1,721	\$ 13,525

As of December 31, 2014	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>								
Cash equivalents <sup>(a)</sup>	\$ 405	\$	\$	\$ 405	\$ 1,119	\$	\$	\$ 1,119
Nuclear decommissioning trust fund investments								
Cash equivalents	208	37		245	208	37		245
Equity								
Domestic	2,423	2,207		4,630	2,423	2,207		4,630
Foreign	612			612	612			612
Equity funds subtotal	3,035	2,207		5,242	3,035	2,207		5,242
Fixed income								
Corporate debt		2,023	239	2,262		2,023	239	2,262
U.S. Treasury and agencies	996			996	996			996
Foreign governments		95		95		95		95
State and municipal debt		438		438		438		438
Other		511		511		511		511
Fixed income subtotal	996	3,067	239	4,302	996	3,067	239	4,302
Middle market lending								
Private Equity			83	83			83	83
Real Estate			3	3			3	3
Other		301		301		301		301

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Nuclear decommissioning trust fund investments subtotal <sup>(b)</sup>	4,239	5,612	691	10,542	4,239	5,612	691	10,542
Pledged assets for Zion Station decommissioning								
Cash equivalents		15		15		15		15
Equities	6	1		7	6	1		7
Fixed income								
U.S. Treasury and agencies	5	3		8	5	3		8
Corporate debt		89		89		89		89
State and municipal debt		10		10		10		10
Other		3		3		3		3
Fixed income subtotal	5	105		110	5	105		110
Middle market lending			184	184			184	184
Pledged assets for Zion Station decommissioning subtotal <sup>(c)</sup>	11	121	184	316	11	121	184	316
Rabbi trust investments <sup>(d)</sup>								
Cash equivalents					1			1
Mutual funds <sup>(e)</sup>	16			16	46			46
Rabbi trust investments subtotal	16			16	47			47
Commodity derivative assets								
Economic hedges	1,667	3,465	1,681	6,813	1,667	3,465	1,681	6,813
Proprietary trading	201	284	27	512	201	284	27	512
Effect of netting and allocation of collateral <sup>(f)</sup>	(1,982)	(2,757)	(557)	(5,296)	(1,982)	(2,757)	(557)	(5,296)
Commodity derivative assets subtotal	(114)	992	1,151	2,029	(114)	992	1,151	2,029

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As of December 31, 2014	Generation				Exelon			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Interest rate and foreign currency derivative assets</b>								
Derivatives designated as hedging instruments		8		8		31		31
Economic hedges		12		12		13		13
Proprietary trading	18	9		27	18	9		27
Effect of netting and allocation of collateral	(17)	(12)		(29)	(17)	(31)		(48)
Interest rate and foreign currency derivative assets subtotal	1	17		18	1	22		23
Other investments			3	3	2		3	5
<b>Total assets</b>	<b>4,558</b>	<b>6,742</b>	<b>2,029</b>	<b>13,329</b>	<b>5,305</b>	<b>6,747</b>	<b>2,029</b>	<b>14,081</b>
<b>Liabilities</b>								
<b>Commodity derivative liabilities</b>								
Economic hedges	(2,241)	(3,458)	(788)	(6,487)	(2,241)	(3,458)	(995)	(6,694)
Proprietary trading	(195)	(295)	(42)	(532)	(195)	(295)	(42)	(532)
Effect of netting and allocation of collateral <sup>(a)</sup>	2,416	3,557	729	6,702	2,416	3,557	729	6,702
Commodity derivative liabilities subtotal	(20)	(196)	(101)	(317)	(20)	(196)	(308)	(524)
<b>Interest rate and foreign currency derivative liabilities</b>								
Derivatives designated as hedging instruments		(12)		(12)		(41)		(41)
Economic hedges		(2)		(2)		(103)		(103)
Proprietary trading	(14)	(9)		(23)	(14)	(9)		(23)
Effect of netting and allocation of collateral	25	10		35	25	29		54
Interest rate and foreign currency derivative liabilities subtotal	11	(13)		(2)	11	(124)		(113)
Deferred compensation obligation		(31)		(31)		(107)		(107)
<b>Total liabilities</b>	<b>(9)</b>	<b>(240)</b>	<b>(101)</b>	<b>(350)</b>	<b>(9)</b>	<b>(427)</b>	<b>(308)</b>	<b>(744)</b>
<b>Total net assets</b>	<b>\$ 4,549</b>	<b>\$ 6,502</b>	<b>\$ 1,928</b>	<b>\$ 12,979</b>	<b>\$ 5,296</b>	<b>\$ 6,320</b>	<b>\$ 1,721</b>	<b>\$ 13,337</b>

(a) Excludes certain cash equivalents considered to be held-to-maturity and not reported at fair value.

(b) Excludes net (liabilities) of \$(27) million and \$(5) million at March 31, 2015 and December 31, 2014, 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 \$1 million and \$3 million at March 31, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) Excludes \$36 million and \$35 million of cash surrender value of life insurance investment at March 31, 2015 and December 31, 2014, respectively, at Exelon Consolidated. Excludes \$12 million and \$11 million and of cash surrender value of life insurance investment at March 31, 2015 and December 31, 2014, respectively, at Generation.

(e) The mutual funds held by the Rabbi trusts at Exelon include \$47 million related to deferred compensation and \$1 million related to Supplemental Executive Retirement Plan at March 31, 2015, and \$45 million related to deferred compensation and \$1 million related to Supplemental Executive Retirement Plan at December 31, 2014.

(f) Includes collateral postings (received) to/from counterparties. Collateral posted (received) to/from counterparties, net of collateral paid to counterparties, totaled \$425 million, \$736 million and \$185 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 2015. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled \$434 million, \$800 million and \$172 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2014.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

*ComEd, PECO and BGE*

The following tables present assets and liabilities measured and recorded at fair value on the utility Registrants' Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2015 and December 31, 2014:

As of March 31, 2015	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$ 67	\$	\$	\$ 67	\$ 5	\$	\$	\$ 5	\$ 75	\$	\$	\$ 75
Rabbi trust investments in mutual funds <sup>(a)</sup>					9			9	5			5
<b>Total assets</b>	67			67	14			14	80			80
<b>Liabilities</b>												
Deferred compensation obligation		(8)		(8)		(14)		(14)		(4)		(4)
Mark-to-market derivative liabilities <sup>(b)</sup>			(241)	(241)								
<b>Total liabilities</b>		(8)	(241)	(249)		(14)		(14)		(4)		(4)
<b>Total net assets (liabilities)</b>	\$ 67	\$ (8)	\$ (241)	\$ (182)	\$ 14	\$ (14)	\$	\$	\$ 80	\$ (4)	\$	\$ 76

As of December 31, 2014	ComEd				PECO				BGE			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
<b>Assets</b>												
Cash equivalents	\$ 25	\$	\$	\$ 25	\$ 12	\$	\$	\$ 12	\$ 103	\$	\$	\$ 103
Rabbi trust investments in mutual funds <sup>(a)</sup>					9			9	5			5
<b>Total assets</b>	25			25	21			21	108			108
<b>Liabilities</b>												
Deferred compensation obligation		(8)		(8)		(15)		(15)		(5)		(5)
Mark-to-market derivative liabilities <sup>(b)</sup>			(207)	(207)								
<b>Total liabilities</b>		(8)	(207)	(215)		(15)		(15)		(5)		(5)
<b>Total net assets (liabilities)</b>	\$ 25	\$ (8)	\$ (207)	\$ (190)	\$ 21	\$ (15)	\$	\$ 6	\$ 108	\$ (5)	\$	\$ 103

(a) At PECO, excludes \$14 million of the cash surrender value of life insurance investments at both March 31, 2015 and December 31, 2014.

(b) The Level 3 balance includes the current and noncurrent liability of \$20 million and \$221 million at March 31, 2015, respectively, and \$20 million and \$187 million at December 31, 2014, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.





**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2015 and 2014:

Three Months Ended	Nuclear Decommissioning Trust Fund Investment	Pledged Assets for Zion Station Decommissioning	Generation			ComEd		Exelon
			Mark-to- Market Derivatives	Other Investments	Total Generation	Mark-to- Market Derivatives <sup>(b)</sup>	Eliminated in Consolidation	Total
<b>March 31, 2015</b>								
Balance as of December 31, 2014	\$ 691	\$ 184	\$ 1,050	\$ 3	\$ 1,928	\$ (207)	\$	\$ 1,721
Total realized / unrealized gains (losses)								
Included in net income	2		(32) <sup>(a)</sup>		(30)			(30)
Included in noncurrent payables to affiliates	8				8		(8)	
Included in payable for Zion Station decommissioning		3			3			3
Included in regulatory assets						(34)	8	(26)
Change in collateral			12		12			12
Purchases, sales, issuances and settlements								
Purchases	47	5	41		93			93
Sales	(8)	(14)			(22)			(22)
Settlements	(29)				(29)			(29)
Transfers into Level 3	4				4			4
Transfers out of Level 3			(5)		(5)			(5)
Balance as of March 31, 2015	\$ 715	\$ 178	\$ 1,066	\$ 3	\$ 1,962	\$ (241)	\$	\$ 1,721
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended March 31, 2015	\$ 1	\$	\$ 180	\$	\$ 181	\$	\$	\$ 181

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Three Months Ended	Nuclear Decommissioning Trust Fund	Pledged Assets for Zion Station Decommissioning	Generation		Total Generation	ComEd	Eliminated in Consolidation	Exelon
			Mark-to- Market Derivatives	Other Investments		Mark-to- Market Derivatives <sup>(b)</sup>		Total
<b>March 31, 2014</b>								
Balance as of December 31, 2013	\$ 350	\$ 112	\$ 465	\$ 15	\$ 942	\$ (193)	\$	\$ 749
Total realized / unrealized gains (losses)								
Included in net income	1		(312) <sup>(a)</sup>		(311)			(311)
Included in noncurrent payables to affiliates	3				3		(3)	
Included in payable for Zion Station decommissioning		(1)			(1)			(1)
Included in regulatory assets						25	3	28
Change in collateral			144		144			144
Purchases, sales, issuances and settlements								
Purchases	139	30	10	2	181			181
Sales	(1)	(4)	(2)		(7)			(7)
Settlements	(6)				(6)			(6)
Transfers into Level 3			(26)		(26)			(26)
Transfers out of Level 3			8	(7)	1			1
Balance as of March 31, 2014	\$ 486	\$ 137	\$ 287	\$ 10	\$ 920	\$ (168)	\$	\$ 752
The amount of total gains (losses) included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the nine months ended								
March 31, 2014	\$	\$	\$ (446)	\$	\$ (446)	\$	\$	\$ (446)

(a) Includes the reclassification of \$212 million and \$(134) million of realized gains (losses) due to the settlement of derivative contracts for the three months ended March 31, 2015 and 2014, respectively.

(b) Includes \$36 million of decreases in fair value and realized losses due to settlements of \$2 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2015. Includes \$30 million of increases in fair value and realized gains due to settlements of \$5 million for the three months ended March 31, 2014.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2015 and 2014:

	Operating Revenues	Generation Purchased Power and Fuel	Other, net <sup>(a)</sup>	Operating Revenues	Exelon Purchased Power and Fuel	Other, net <sup>(a)</sup>
Total gains (losses) included in net income for the three months ended March 31, 2015	(10)	(22)	2	(10)	(22)	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2015	169	11	1	169	11	1
Total gains (losses) included in net income for the three months ended March 31, 2014	\$ (268)	\$ (44)	\$ 1	\$ (268)	\$ (44)	\$ 1
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2014	(425)	(21)		(425)	(21)	

(a) Other, net activity consists of realized and unrealized gains (losses) included in income for the NDT funds held by Generation.

**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, PECO and BGE).* 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 Generation's and CENG's nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds and mutual funds, which are included in Equities, Fixed Income and Other. Generation's and CENG'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 or Level 2.

With respect to individually held equity securities, which are included in Domestic or Foreign equities, 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.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

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. The fair values of private placement fixed income securities, which are included in Corporate debt, are determined using a third party valuation that contains significant unobservable inputs and are categorized in Level 3.

Equity, balanced 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, Generation, and CENG invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities.

Middle market lending are investments in loans or managed funds which invest in private companies. Generation elected the fair value option for its investments in certain limited partnerships that invest in middle market lending managed funds. The fair value of these loans is determined using a combination of valuation models including cost models, market models, and income models. Investments in middle market lending are categorized as Level 3 because the fair value of these securities is based largely on inputs that are unobservable and utilize complex valuation models. Investments in middle market lending typically cannot be redeemed until maturity of the term loan.

Private equity investments include investments in operating companies that are not publicly traded on a stock exchange. 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.

As of March 31, 2015, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately \$265 million. These commitments will be funded by Generation's existing nuclear decommissioning trust funds.

See Note 12 Nuclear Decommissioning for further discussion on the NDT fund investments.

*Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE).* 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 Rabbi trusts assets are included in investments in the Registrants' Consolidated Balance Sheets and consist primarily of mutual funds and life insurance policies. The

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

mutual 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. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The life insurance policies are valued using the cash surrender value of the policies, which is provided by a third party. The cash surrender value inputs are not observable.

*Mark-to-Market Derivatives (Exelon, Generation, and ComEd).* Derivative contracts are traded in both exchange-based and non-exchange-based markets. Exchange-based derivatives that are valued using unadjusted quoted prices in active markets are categorized in Level 1 in the fair value hierarchy. Certain derivatives' pricing is verified using indicative price quotations available through brokers or over-the-counter, on-line exchanges 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 derivative contracts are valued using the Black model, an industry standard option valuation model. The Black model takes into account inputs such as contract terms, including maturity, and market parameters, including assumptions of the future prices of energy, interest rates, volatility, credit worthiness and credit spread. For derivatives that trade in liquid markets, such as generic forwards, swaps and options, model inputs are generally observable. Such instruments are categorized in Level 2. The Registrants' derivatives are predominately at liquid trading points. For derivatives that trade in less liquid markets with limited pricing information model inputs generally would include both observable and unobservable inputs. These valuations may include an estimated basis adjustment from an illiquid trading point to a liquid trading point for which active price quotations are available. Such instruments are categorized in Level 3.

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, 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. 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 8 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

*Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE).* 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 underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

***Additional Information Regarding Level 3 Fair Value Measurements (Exelon, Generation, ComEd)***

*Mark-to-Market Derivatives (Exelon, Generation, ComEd).* For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon's RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief risk officer and includes the chief financial officer, corporate controller, general counsel, treasurer, vice president of strategy, vice president of audit services and officers representing Exelon's business units. The RMC reports to the Exelon Board of Directors on the scope of the risk management activities and is responsible for approving all valuation procedures at Exelon. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

Disclosed below is detail surrounding the Registrants' significant Level 3 valuations. The calculated fair value includes marketability discounts for margining provisions and other attributes. Generation's Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, certain transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation's own credit quality for liabilities. The level of observability of a forward commodity price varies generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are more liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location. This spread does not typically represent a majority of the instrument's market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is approximately \$3.15 and \$0.31 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant's mark-to-market derivative assets and liabilities.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 8 Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade		Fair Value at March 31, 2015	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Hedges (Generation) <sup>(a)(c)</sup>	Economic	\$ 892	Discounted		
			Cash Flow	Forward power price	\$17 - \$121 <sup>(d)</sup>
				Forward gas price	\$1.68 - \$13.69 <sup>(d)</sup>
			Option Model	Volatility percentage	8% - 172%
Mark-to-market derivatives (Generation) <sup>(a)(c)</sup>	Proprietary trading	\$ (11)	Discounted		
			Cash Flow	Forward power price	\$17 - \$95 <sup>(d)</sup>
Mark-to-market derivatives (ComEd)		\$ (241)	Discounted		
			Cash Flow	Forward heat rate <sup>(b)</sup>	8x - 9x
				Marketability reserve	3.5% - 8%
				Renewable factor	86% - 126%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.

(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

(c) The fair values do not include cash collateral held on level three positions of \$185 million as of March 31, 2015.

(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas economic hedges would be approximately \$107 and \$8.19, respectively, and would be approximately \$55 for power proprietary trading.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Type of trade		Fair Value at December 31, 2014	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives	Economic Hedges (Generation) <sup>(a)(c)</sup>		Discounted		
		\$ 893	Cash Flow	Forward power price	\$15 - \$120 <sup>(d)</sup>
				Forward gas price	\$1.52 - \$14.02 <sup>(d)</sup>
			Option Model	Volatility percentage	8% 257%
Mark-to-market derivatives (Generation) <sup>(a)(c)</sup>	Proprietary trading		Discounted		
		\$ (15)	Cash Flow	Forward power price	\$15 - \$117 <sup>(d)</sup>
Mark-to-market derivatives (ComEd)		\$ (207)	Discounted		
			Cash Flow	Forward heat rate <sup>(b)</sup>	8x - 9x
				Marketability reserve	3.5% - 8%
				Renewable factor	86% - 126%

(a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.

(b) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract's delivery.

(c) The fair values do not include cash collateral held on level three positions of \$172 million as of December 31, 2014.

(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately \$97 and \$8.14, respectively, and would be approximately \$76 for power proprietary trading.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation's commodity derivatives are forward commodity prices and for options is price volatility. Increases (decreases) in the forward commodity price in isolation would result in significantly higher (lower) fair values for long positions (contracts that give Generation the obligation or option to purchase a commodity), with offsetting impacts to short positions (contracts that give Generation the obligation or right to sell a commodity). Increases (decreases) in volatility would increase (decrease) the value for the holder of the option (writer of the option). Generally, a change in the estimate of forward commodity prices is unrelated to a change in the estimate of volatility of prices. An increase to the reserves listed above would decrease the fair value of the positions. An increase to the heat rate or renewable factors would increase the fair value accordingly. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets.

*Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation).* For middle market lending, certain corporate debt securities, and private equity investments, the fair value is determined using a combination of valuation models including cost models, market models and income models. The valuation estimates are based on valuations of comparable companies, discounting the forecasted cash flows of the portfolio company, estimating the liquidation or collateral value of the portfolio company or its assets, considering offers from third parties to buy the portfolio company, its historical and projected financial results, as well as other factors that may impact value. Significant judgment is required in the application of discounts or premiums applied to the prices of comparable companies for factors such as size, marketability, credit risk and relative performance.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

Because Generation relies on third-party fund managers to develop the quantitative unobservable inputs without adjustment for the valuations of its Level 3 investments, quantitative information about significant unobservable inputs used in valuing these investments is not reasonably available to Generation. This includes information regarding the sensitivity of the fair values to changes in the unobservable inputs. Generation gains an understanding of the fund managers' inputs and assumptions used in preparing the valuations. Generation performed procedures to assess the reasonableness of the valuations. For a sample of its Level 3 investments, Generation reviewed independent valuations and reviewed the assumptions in the detailed pricing models used by the fund managers.

**8. Derivative Financial Instruments (Exelon, Generation, ComEd, PECO and BGE)**

The Registrants use derivative instruments to manage commodity price risk and interest rate risk related to ongoing business operations.

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

To the extent the amount of energy Generation produces differs from the amount of energy it has contracted to sell, Exelon and Generation are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. Each of the Registrants employ established policies and procedures to manage their risks associated with market fluctuations in commodity prices by entering into physical and 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.

Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the Constellation merger. Because the underlying forecasted transactions remained probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and was reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurred. The effect of this decision is that all derivative economic hedges related to commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 22 – Commitments and Contingencies of the Exelon 2014 Form 10-K. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's overall energy marketing activities.

***Economic Hedging.*** 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. As such, Generation uses a variety of derivative and non-derivative instruments to manage the

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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

commodity price risk of its electric generation facilities, including power and gas sales, fuel and energy purchases, natural gas transportation and pipeline capacity agreements and other energy-related products marketed and purchased. In order to manage these risks, Generation may enter into fixed-price derivative or non-derivative contracts to hedge the variability in future cash flows from forecasted sales of energy and gas and purchases of fuel and energy. The objectives for entering into such hedges include fixing the price for a portion of anticipated future electricity sales at a level that provides an acceptable return on electric generation operations, fixing the price of a portion of anticipated fuel purchases for the operation of power plants, and fixing the price for a portion of anticipated energy purchases to supply load-serving customers. The portion of forecasted transactions hedged may vary based upon management's policies and hedging objectives, the market, weather conditions, operational and other factors. Generation is also exposed to differences between the locational settlement prices of certain economic hedges and the hedged generating units. This price difference is actively managed through other instruments which include derivative congestion products, whose changes in fair value are recognized in earnings each period, and auction revenue rights, which are accounted for on an accrual basis.

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation's owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of March 31, 2015, the proportion of expected generation hedged is for the major reportable segments was 94%-97%, 67%-70%, and 37%-40% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales to ComEd, PECO and BGE to serve their retail load.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts for energy and associated RECs were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reductions was approved in March 2014. 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. See Note 3 - Regulatory Matters of the Exelon 2014 Form 10-K for additional information.

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 - Regulatory Matters. Based on Pennsylvania legislation and the DSP Programs permitting PECO to recover its electric supply procurement costs from retail customers with no mark-up, PECO's price risk related to electric supply procurement is limited. PECO locked in fixed prices for a significant portion of its commodity price risk through full requirements contracts and block contracts. PECO has certain full requirements contracts and block contracts that are considered derivatives and qualify for the NPNS scope exception under current derivative authoritative guidance.

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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 NPNS 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 2014 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 2014 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO's gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO's financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

BGE has contracts to procure SOS electric supply that are executed through a competitive procurement process approved by the MDPSC. The SOS rates charged recover BGE's wholesale power supply costs and include an administrative fee. The administrative fee includes an incremental cost component and a shareholder return component for commercial and industrial rate classes. BGE's price risk related to electric supply procurement is limited. BGE locks in fixed prices for all of its SOS requirements through full requirements contracts. Certain of BGE's full requirements contracts, which are considered derivatives, qualify for the NPNS scope exception under current derivative authoritative guidance. Other BGE full requirements contracts are not derivatives.

BGE provides natural gas to its customers under a MBR mechanism approved by the MDPSC. Under this mechanism, BGE's actual cost of gas is compared to a market index (a measure of the market price of gas in a given period). The difference between BGE's actual cost and the market index is shared equally between shareholders and customers. BGE must also secure fixed price contracts for at least 10%, but not more than 20%, of forecasted system supply requirements for flowing (i.e., non-storage) gas for the November through March period. These fixed-price contracts are not subject to sharing under the MBR mechanism. BGE also ensures it has sufficient pipeline transportation capacity to meet customer requirements. All of BGE's natural gas supply and asset management agreements qualify for the NPNS scope exception and result in physical delivery.

*Proprietary Trading.* Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading activities, which included settled physical sales volumes of 1,808 GWhs and 2,494 GWhs for the three months ended March 31, 2015 and 2014, respectively, are a complement to Generation's energy marketing portfolio but represent a small portion of Generation's revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

***Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)***

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants 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 rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

strategies are employed to manage interest rate risks. At March 31, 2015, Exelon had \$900 million of notional amounts of fixed-to-floating hedges outstanding, and Exelon and Generation had \$3,068 million and \$768 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately \$1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 2015. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges. Below is a summary of the interest rate and foreign currency hedges as of March 31, 2015.

Description	Generation				Other				Exelon	
	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading <sup>(a)</sup>	Collateral and Netting <sup>(b)</sup>	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting <sup>(b)</sup>		Subtotal
Mark-to-market derivative assets (current assets)	\$	\$ 13	\$ 11	\$ (10)	\$ 14	\$ 1	\$	\$	\$ 1	\$ 15
Mark-to-market derivative assets (noncurrent assets)		14	8	(3)	19	31	2	(31)	2	21
<b>Total mark-to-market derivative assets</b>		<b>27</b>	<b>19</b>	<b>(13)</b>	<b>33</b>	<b>32</b>	<b>2</b>	<b>(31)</b>	<b>3</b>	<b>36</b>
Mark-to-market derivative liabilities (current liabilities)	(8)	(6)	(8)	15	(7)					(7)
Mark-to-market derivative liabilities (noncurrent liabilities)	(9)		(7)	6	(10)		(180)	31	(149)	(159)
<b>Total mark-to-market derivative liabilities</b>	<b>(17)</b>	<b>(6)</b>	<b>(15)</b>	<b>21</b>	<b>(17)</b>		<b>(180)</b>	<b>31</b>	<b>(149)</b>	<b>(166)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ (17)</b>	<b>\$ 21</b>	<b>\$ 4</b>	<b>\$ 8</b>	<b>\$ 16</b>	<b>\$ 32</b>	<b>\$ (178)</b>	<b>\$</b>	<b>\$ (146)</b>	<b>\$ (130)</b>

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts within the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

The following table provides a summary of the interest rate and foreign exchange hedge balances recorded by the Registrants as of December 31, 2014:

Description	Generation					Other			Subtotal	Exelon Total
	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading <sup>(a)</sup>	Collateral and Netting <sup>(b)</sup>	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting <sup>(b)</sup>		
Mark-to-market derivative assets (current assets)	\$ 7	\$ 7	\$ 20	\$ (22)	\$ 12	\$ 3	\$	\$	\$ 3	\$ 15
Mark-to-market derivative assets (noncurrent assets)	1	5	7	(7)	6	20	1	(19)	2	8
<b>Total mark-to-market derivative assets</b>	<b>8</b>	<b>12</b>	<b>27</b>	<b>(29)</b>	<b>18</b>	<b>23</b>	<b>1</b>	<b>(19)</b>	<b>5</b>	<b>23</b>
Mark-to-market derivative liabilities (current liabilities)	(8)	(2)	(14)	25	1					1
Mark-to-market derivative liabilities (noncurrent liabilities)	(4)		(9)	10	(3)	(29)	(101)	19	(111)	(114)
<b>Total mark-to-market derivative liabilities</b>	<b>(12)</b>	<b>(2)</b>	<b>(23)</b>	<b>35</b>	<b>(2)</b>	<b>(29)</b>	<b>(101)</b>	<b>19</b>	<b>(111)</b>	<b>(113)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ (4)</b>	<b>\$ 10</b>	<b>\$ 4</b>	<b>\$ 6</b>	<b>\$ 16</b>	<b>\$ (6)</b>	<b>\$ (100)</b>	<b>\$</b>	<b>\$ (106)</b>	<b>\$ (90)</b>

(a) Generation enters into interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions. The characterization of the interest rate derivative contracts within the proprietary trading activity in the above table is driven by the corresponding characterization of the underlying commodity position that gives rise to the interest rate exposure. Generation does not utilize proprietary trading interest rate derivatives with the objective of benefiting from shifts or changes in market interest rates.

(b) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as accrued interest, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.



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*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:

	Income Statement Location	Three Months Ended March 31,			
		2015	2014	2015	2014
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense <sup>(a)</sup>	\$ (1)	\$ (5)	\$	\$ (1)
Exelon	Interest expense	9	2	11	4

(a) For the three months ended March 31, 2015 and 2014, the loss on Generation swaps included \$1 million and \$4 million realized in earnings with an immaterial amount excluded from hedge effectiveness testing.

At March 31, 2015, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of \$900 million, with a derivative asset of \$32 million. At December 31, 2014, Exelon and Generation had outstanding fixed-to-floating fair value hedges related to interest rate swaps of \$1,450 million and \$550 million, with a derivative asset of \$29 million and \$7 million, respectively. During the three months ended March 31, 2015 and 2014, the impact on the results of operations as a result of the ineffectiveness from fair value hedges was a \$4 million and a \$5 million gain, respectively.

*Cash Flow Hedges.* During 2014, Exelon entered into \$400 million of floating-to-fixed forward starting interest rate swaps to manage a portion of the interest rate exposure associated with the anticipated refinancing of existing debt. The swaps are designated as cash flow hedges. In January 2015, in connection with Generation's \$750 million issuance of five-year Senior Unsecured Notes, Exelon terminated these swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, \$26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.

During the third quarter of 2014, ExGen Texas Power, LLC, a subsidiary of Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with a long-term borrowing. See Note 13 Debt and Credit Agreements of the Exelon 2014 Form 10-K for additional information regarding the financing. The swaps have a notional amount of \$504 million as of March 31, 2015 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At March 31, 2015, the subsidiary had a \$13 million derivative liability related to the swap.

During the first quarter of 2014, ExGen Renewables I, LLC, a subsidiary of Exelon Generation, entered into floating-to-fixed interest rate swaps to manage a portion its interest rate exposure in connection with long-term borrowings. See Note 13 Debt and Credit Agreements of the Exelon 2014 Form 10-K for additional information regarding the financing. The swaps have a notional amount of \$212 million as of March 31, 2015 and expire in 2020. The swaps are designated as cash flow hedges. At March 31, 2015, the subsidiary had a \$3 million derivative liability related to the swaps.

During the three months ended March 31, 2015 and 2014, the impact on the results of operations as a result of ineffectiveness from cash flow hedges in continuing designated hedge relationships were immaterial.

*Economic Hedges.* During the third quarter of 2011, Sacramento PV Energy, a subsidiary of Generation entered into floating-to-fixed interest rate swaps to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13 Debt and Credit Agreements of the Exelon 2014 Form 10-K for additional information regarding the financing. The swaps have a total notional amount of \$26 million as of



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

March 31, 2015 and expire in 2027. After the closing of the Constellation merger, the swaps were re-designated as cash flow hedges. During the first quarter of 2015, the swaps were de-designated as the forecasted transaction was no longer probable of occurring. The balance in Accumulated OCI was frozen as of the date of de-designation and will amortize into Interest expense over the remaining term of the forecasted transaction. All future changes in fair value are reflected in Interest expense. At March 31, 2015, the subsidiary had a \$3 million derivative liability related to these swaps, which included an immaterial amount that was amortized to Interest expense after de-designation.

During the third quarter of 2012, Constellation Solar Horizon, a subsidiary of Exelon Generation, entered into a floating-to-fixed interest rate swap to manage a portion of its interest rate exposure in connection with the long-term borrowings. See Note 13 Debt and Credit Agreements of the Exelon 2014 Form 10-K for additional information regarding the financing. The swap has a notional amount of \$26 million as of March 31, 2015 and expires in 2030. This swap was designated as a cash flow hedge. During the first quarter of 2015, the swaps were de-designated as the forecasted transaction was no longer probable of occurring. The balance in OCI was frozen as of the date of de-designation and will amortize into Interest expense over the remaining term of the forecasted transaction. All future changes in fair value are reflected in Interest expense. At March 31, 2015, the subsidiary had an immaterial derivative liability related to the swap.

Through March 31, 2015, Exelon entered into \$2,300 million of floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed merger with PHL. At March 31, 2015, Exelon had a \$178 million derivative liability related to the swaps.

At March 31, 2015, Generation had \$271 million in notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and \$338 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

***Fair Value Measurement and Accounting for the Offsetting of Amounts Related to Certain Contracts (Exelon, Generation, ComEd, PECO and BGE)***

Fair value accounting guidance and disclosures about offsetting assets and liabilities 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 legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation's use of cash collateral is generally unrestricted, unless Generation is downgraded below investment grade (i.e., to BB+ or Ba1). In the table below, Generation's energy related economic hedges and proprietary trading derivatives are shown gross. The impact of the netting of fair value balances with the same counterparty that are subject to legally enforceable master netting agreements, as well as netting of cash collateral, including initial margin on exchange positions, is aggregated in the collateral and netting column. As of March 31, 2015 and December 31, 2014, \$5 million and \$8 million of cash collateral posted, respectively, was not offset against derivative positions because such collateral was not associated with any energy-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. Excluded from the tables below are economic hedges that qualify for the NPNS scope exception and other non-derivative contracts that are accounted for under the accrual method of accounting.

ComEd's use of cash collateral is generally unrestricted, unless ComEd is downgraded below investment grade (i.e., to BB+ or Ba1).

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Cash collateral held by PECO and BGE must be deposited in a non-affiliate major U.S. commercial bank or foreign bank with a U.S. branch office that meet certain qualifications.

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of March 31, 2015:

Derivatives	Economic Hedges	Proprietary Trading	Generation	Subtotal <sup>(b)</sup>	ComEd	Exelon
			Collateral and Netting <sup>(a)</sup>		Economic Hedges <sup>(c)</sup>	Total Derivatives
Mark-to-market derivative assets (current assets)	\$ 4,618	\$ 431	\$ (3,947)	\$ 1,102	\$	\$ 1,102
Mark-to-market derivative assets (noncurrent assets)	2,363	70	(1,541)	892		892
<b>Total mark-to-market derivative assets</b>	<b>6,981</b>	<b>501</b>	<b>(5,488)</b>	<b>1,994</b>		<b>1,994</b>
Mark-to-market derivative liabilities (current liabilities)	(4,505)	(437)	4,852	(90)	(20)	(110)
Mark-to-market derivative liabilities (noncurrent liabilities)	(2,016)	(77)	1,982	(111)	(221)	(332)
<b>Total mark-to-market derivative liabilities</b>	<b>(6,521)</b>	<b>(514)</b>	<b>6,834</b>	<b>(201)</b>	<b>(241)</b>	<b>(442)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ 460</b>	<b>\$ (13)</b>	<b>\$ 1,346</b>	<b>\$ 1,793</b>	<b>\$ (241)</b>	<b>\$ 1,552</b>

- (a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, letters of credit and other forms of non-cash collateral. These are not reflected in the table above.
- (b) Current and noncurrent assets are shown net of collateral of \$387 million and \$192 million, respectively, and current and noncurrent liabilities are shown net of collateral of \$519 million and \$248 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was \$1,346 million at March 31, 2015.
- (c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

The following table provides a summary of the derivative fair value balances recorded by the Registrants as of December 31, 2014:

Description	Generation			Subtotal <sup>(b)</sup>	ComEd	Exelon
	Economic Hedges	Proprietary Trading	Collateral and Netting <sup>(a)</sup>		Economic Hedges <sup>(c)</sup>	Total Derivatives
Mark-to-market derivative assets (current assets)	\$ 4,992	\$ 456	\$ (4,184)	\$ 1,264	\$	\$ 1,264
Mark-to-market derivative assets (noncurrent assets)	1,821	56	(1,112)	765		765
<b>Total mark-to-market derivative assets</b>	<b>6,813</b>	<b>512</b>	<b>(5,296)</b>	<b>2,029</b>		<b>2,029</b>
Mark-to-market derivative liabilities (current liabilities)	(4,947)	(468)	5,200	(215)	(20)	(235)
Mark-to-market derivative liabilities (noncurrent liabilities)	(1,540)	(64)	1,502	(102)	(187)	(289)
<b>Total mark-to-market derivative liabilities</b>	<b>(6,487)</b>	<b>(532)</b>	<b>6,702</b>	<b>(317)</b>	<b>(207)</b>	<b>(524)</b>
<b>Total mark-to-market derivative net assets (liabilities)</b>	<b>\$ 326</b>	<b>\$ (20)</b>	<b>\$ 1,406</b>	<b>\$ 1,712</b>	<b>\$ (207)</b>	<b>\$ 1,505</b>

(a) Exelon and Generation net all available amounts allowed under the derivative accounting guidance on the balance sheet. These amounts include unrealized derivative transactions with the same counterparty under legally enforceable master netting agreements and cash collateral. In some cases Exelon and Generation may have other offsetting exposures, subject to a master netting or similar agreement, such as trade receivables and payables, transactions that do not qualify as derivatives, and letters of credit. These are not reflected in the table above.

(b) Current and noncurrent assets are shown net of collateral of \$416 million and \$171 million, respectively, and current and noncurrent liabilities are shown net of collateral of \$599 million and \$220 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was \$1,406 million at December 31, 2014.

(c) Includes current and noncurrent liabilities relating to floating-to-fixed energy swap contracts with unaffiliated suppliers.

*Cash Flow Hedges (Exelon, Generation and ComEd).* As discussed previously, effective prior to the Constellation merger, Generation de-designated all of its cash flow hedges relating to commodity price risk. Because the underlying forecasted transactions remain at least reasonably probable, the fair value of the effective portion of these cash flow hedges was frozen in Accumulated OCI and is reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. Generation began recording prospective changes in the fair value of these instruments through current earnings from the date of de-designation. As of March 31, 2015, no unrealized balance remains in accumulated OCI to be reclassified by Generation.

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

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three months ended March 31, 2015 and 2014, 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.

	Income Statement Location	Total Cash Flow Hedge OCI Activity,	
		Generation Total Cash Flow Hedges	Net of Income Tax Exelon Total Cash Flow Hedges
<b>Three Months Ended March 31, 2015</b>			
Accumulated OCI derivative gain at December 31, 2014		\$ (18)	\$ (28)
Effective portion of changes in fair value		(6)	(11)
Reclassifications from accumulated OCI to net income	Other, net		16 <sup>(a)</sup>
Reclassifications from accumulated OCI to net income	Interest Expense	3	3
Reclassifications from accumulated OCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative gain at March 31, 2015		\$ (23)	\$ (22)

(a) Amount is net of related income tax expense of \$10 million for the three months ended March 31, 2015.

	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
<b>Three Months Ended March 31, 2014</b>			
Accumulated OCI derivative gain at December 31, 2013		\$ 116	\$ 120
Effective portion of changes in fair value		(4)	(1)
Reclassifications from accumulated OCI to net income	Operating Revenues	(24) <sup>(a)</sup>	(24) <sup>(a)</sup>
Accumulated OCI derivative gain at March 31, 2014		\$ 88	\$ 95

(a) Amount is net of related income tax expense of \$15 million for the three months ended March 31, 2014.

The effect of Exelon's and Generation's former energy-related cash flow hedge activity on pre-tax earnings based on the reclassification adjustment from accumulated OCI to earnings was a \$2 million pre-tax gain for the three months ended March 31, 2015, and a \$39 million pre-tax gain for the three months ended March 31, 2014. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

*Economic Hedges (Exelon and Generation).* These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made.



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Additionally, Generation enters into interest rate derivative contracts and foreign exchange currency swaps ( treasury ) to manage the exposure related to the interest rate component of commodity positions and international purchases of commodities in currencies other than U.S. Dollars. Exelon entered into floating-to-fixed forward starting interest rate swaps to manage interest rate risks associated with anticipated future debt issuance related to the proposed PHI acquisition. For the three months ended March 31, 2015 and 2014, the following pre-tax mark-to-market gains (losses) of certain purchase and sale contracts were reported in operating revenues or purchased power and fuel expense, or interest 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.

		Generation			HoldCo	Exelon
	Operating	Purchased	Interest	Total	Interest	Total
Three Months Ended March 31, 2015	Revenues	Power and Fuel	Expense		Expense	
Change in fair value of commodity positions	\$ 164	\$ (79)	\$	\$ 85	\$	\$ 85
Reclassification to realized at settlement of commodity positions	(21)	87		66		66
Net commodity mark-to-market gains (losses)	143	8		151		151
Change in fair value of treasury positions	13			13	(78)	(65)
Reclassification to realized at settlement of treasury positions	(2)			(2)		(2)
Net treasury mark-to-market gains (losses)	11			11	(78)	(67)
Total Net mark-to-market gains (losses)	\$ 154	\$ 8	\$	\$ 162	\$ (78)	\$ 84

		Generation			HoldCo	Exelon
	Operating	Purchased	Interest	Total	Interest	Total
Three Months Ended March 31, 2014	Revenues	Power and Fuel	Expense		Expense	
Change in fair value of commodity positions	\$ (852)	\$ 171	\$	\$ (681)	\$	\$ (681)
Reclassification to realized at settlement of commodity positions	93	(141)		(48)		(48)
Net commodity mark-to-market gains (losses)	(759)	30		(729)		(729)
Change in fair value of treasury positions	(1)		(1)	(2)		(2)
Reclassification to realized at settlement of treasury positions						
Net treasury mark-to-market gains (losses)	(1)		(1)	(2)		(2)
Total Net mark-to-market gains (losses)	\$ (760)	\$ 30	\$ (1)	\$ (731)	\$	\$ (731)

*Proprietary Trading Activities (Exelon and Generation).* For the three months ended March 31, 2015 and 2014, 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



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gains (losses) (before income taxes) relating to mark-to-market activity on commodity derivative instruments entered into for proprietary trading purposes and interest rate derivative contracts to hedge risk associated with the interest rate component of underlying commodity positions. Gains and losses associated with proprietary trading are reported as operating revenue in Exelon's and

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

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	Three Months Ended March 31,	
		2015	2014
Change in fair value of commodity positions	Operating Revenues	\$ 1	\$ (3)
Reclassification to realized at settlement of commodity positions	Operating Revenues	2	1
Net commodity mark-to-market gains (losses)	Operating Revenues	3	(2)
Change in fair value of treasury positions	Operating Revenues	4	
Reclassification to realized at settlement of treasury positions	Operating Revenues	(4)	
Net treasury mark-to-market gains (losses)	Operating Revenues		
Total Net mark-to-market gains (losses)	Operating Revenues	\$ 3	\$ (2)

**Credit Risk (Exelon, Generation, ComEd, PECO and BGE)**

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 process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation's credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

The following tables provide information on Generation's credit exposure for all derivative instruments, NPNS, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of March 31, 2015. The tables further delineate that exposure by credit rating of the counterparties and provide guidance on the concentration of credit risk to individual counterparties. The figures in the table below exclude credit risk exposure from individual retail counterparties, Nuclear fuel procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, further discussed in ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of \$52 million, \$36 million and \$26 million, as of March 31, 2015, respectively.

<b>Rating as of March 31, 2015</b>	<b>Total Exposure Before Credit Collateral</b>	<b>Credit Collateral<sup>(a)</sup></b>	<b>Net Exposure</b>	<b>Number of Counterparties Greater than 10% of Net Exposure</b>	<b>Net Exposure of Counterparties Greater than 10% of Net Exposure</b>
Investment grade	\$ 1,570	\$ 56	\$ 1,514	1	\$ 442
Non-investment grade	63	16	47		
No external ratings					
Internally rated investment grade	495		495		
Internally rated non-investment grade	68	3	65		
<b>Total</b>	<b>\$ 2,196</b>	<b>\$ 75</b>	<b>\$ 2,121</b>	<b>1</b>	<b>\$ 442</b>

<b>Net Credit Exposure by Type of Counterparty</b>	<b>As of March 31, 2015</b>
Financial institutions	\$ 324
Investor-owned utilities, marketers, power producers	897
Energy cooperatives and municipalities	869
Other	31
<b>Total</b>	<b>\$ 2,121</b>

(a) As of March 31, 2015, credit collateral held from counterparties where Generation had credit exposure included \$62 million of cash and \$14 million of letters of credit.

ComEd's power procurement contracts provide suppliers with a certain amount of unsecured credit. The credit position is based on forward market prices compared to the benchmark prices. The benchmark prices are the forward prices of energy projected through the contract term and are set at the point of supplier bid submittals. If the forward market price of energy exceeds the benchmark price, the suppliers are required to post collateral for the secured credit portion after adjusting for any unpaid deliveries and unsecured credit allowed under the contract. The unsecured credit used by the suppliers represents ComEd's net credit exposure. As of March 31, 2015, ComEd's net credit exposure to suppliers was immaterial.

ComEd is permitted to recover its costs of procuring energy through the Illinois Settlement Legislation. ComEd's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information.

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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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of March 31, 2015, PECO is currently holding \$2 million in collateral from 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 5 Regulatory Matters for additional information.

PECO's natural gas procurement plan is reviewed and approved annually on a prospective basis by the PAPUC. PECO's counterparty credit risk under its natural gas supply and asset management agreements is mitigated by its ability to recover its natural gas costs through the PGC, which allows PECO to adjust rates quarterly to reflect realized natural gas prices. PECO does not obtain collateral from suppliers under its natural gas supply and asset management agreements. As of March 31, 2015, PECO had no credit exposure under its natural gas supply and asset management agreements with investment grade suppliers.

BGE is permitted to recover its costs of procuring energy through the MDPSC-approved procurement tariffs. BGE's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 5 Regulatory Matters for additional information.

BGE's full requirement wholesale electric power agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier, or its guarantor, to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth, subject to an unsecured credit cap. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents BGE's net credit exposure. The seller's credit exposure is calculated each business day. As of March 31, 2015, BGE had no net credit exposure to suppliers.

BGE's regulated gas business is exposed to market-price risk. This market-price risk is mitigated by BGE's recovery of its costs to procure natural gas through a gas cost adjustment clause approved by the MDPSC. BGE does make off-system sales after BGE has satisfied its customers demands, which are not covered by the gas cost adjustment clause. At March 31, 2015, BGE had credit exposure of \$4 million related to off-system sales which is mitigated by parental guarantees, letters of credit, or right to offset clauses within other contracts with those third-party suppliers.

***Collateral and Contingent-Related Features (Exelon, Generation, ComEd, PECO and BGE)***

As part of the normal course of business, Generation routinely enters into physical or financially settled contracts for the purchase and sale of electric capacity, energy, fuels, emissions allowances and other energy-related products. Certain of Generation's derivative instruments contain provisions that require Generation to post collateral. Generation also enters into commodity transactions on exchanges (i.e. NYMEX, ICE). The exchanges act as the counterparty to each trade. Transactions on the exchanges must adhere to comprehensive collateral and margining requirements. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Generation's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit-risk-related

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

contingent features stipulate that if Generation were to be downgraded or lose its investment grade credit rating (based on its senior unsecured debt rating), it would be required to provide additional collateral. This incremental collateral requirement allows for the offsetting of derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master netting agreements. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e., capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below.

The aggregate fair value of all derivative instruments with credit-risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the exchanges that are fully collateralized) is detailed in the table below:

<b>Credit-Risk Related Contingent Feature</b>	<b>March 31, 2015</b>	<b>December 31, 2014</b>
Gross Fair Value of Derivative Contracts Containing this Feature <sup>(a)</sup>	\$ (1,420)	\$ (1,433)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements <sup>(b)</sup>	1,138	1,140
<b>Net Fair Value of Derivative Contracts Containing This Feature<sup>(c)</sup></b>	<b>\$ (282)</b>	<b>\$ (293)</b>

- (a) Amount represents the gross fair value of out-of-the-money derivative contracts containing credit-risk related contingent features ignoring the effects of master netting agreements.
- (b) Amount represents the offsetting fair value of in-the-money derivative contracts under legally enforceable master netting agreements with the same counterparty, which reduces the amount of any liability for which a Registrant could potentially be required to post collateral.
- (c) Amount represents the net fair value of out-of-the-money derivative contracts containing credit-risk related contingent features after considering the mitigating effects of offsetting positions under master netting arrangements and reflects the actual net liability upon which any potential contingent collateral obligations would be based.

Generation had cash collateral posted of \$1,428 million and letters of credit posted of \$626 million and cash collateral held of \$69 million and letters of credit held of \$22 million as of March 31, 2015 for counterparties with derivative positions. Generation had cash collateral posted of \$1,497 million and letters of credit posted of \$672 million and cash collateral held of \$77 million and letters of credit held of \$24 million at December 31, 2014 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody's), Generation would have been required to post additional collateral of \$2.3 billion and \$2.4 billion as of March 31, 2015 and December 31, 2014, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation's and Exelon's interest rate swaps contain provisions that, in the event of a merger, if Generation's debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of March 31, 2015, Generation's swaps were in an asset with a fair value of \$16 million and Exelon's swaps were in a liability position, with a fair value of \$(130) million, respectively.

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See Note 24 Segment Information of the Exelon 2014 Form 10-K for further information regarding the letters of credit supporting the cash collateral.

Generation entered into supply forward contracts with certain utilities, including PECO and BGE, with one-sided collateral postings only from Generation. If market prices fall below the benchmark price levels in these contracts, the utilities are not required to post collateral. However, when market prices rise above the benchmark price levels, counterparty suppliers, including Generation, are required to post collateral once certain unsecured credit limits are exceeded. Under the terms of 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 March 31, 2015, ComEd held approximately \$2 million collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd's annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd's long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of March 31, 2015, 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 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional 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 March 31, 2015, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of March 31, 2015, PECO could have been required to post approximately \$36 million of collateral to its counterparties.

PECO's supplier master agreements that govern the terms of its DSP Program contracts do not contain provisions that would require PECO to post collateral.

BGE's full requirements wholesale power agreements that govern the terms of its electric supply procurement contracts do not contain provisions that would require BGE to post collateral.

BGE's natural gas procurement contracts contain provisions that could require BGE to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon BGE's credit rating from the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. As of March 31, 2015, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of March 31, 2015, BGE could have been required to post approximately \$111 million of collateral to its counterparties.

**9. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)*****Short-Term Borrowings***

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool.

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The Registrants had the following amounts of commercial paper borrowings outstanding as of March 31, 2015 and December 31, 2014:

<b>Commercial Paper Borrowings</b>	<b>March 31, 2015</b>	<b>December 31, 2014</b>
Exelon Corporate	\$	\$
Generation		
ComEd	283	304
PECO		
BGE		120

**Credit Facilities**

Exelon had bank lines of credit under committed credit facilities at March 31, 2015 for short-term financial needs, as follows:

<b>Type of Credit Facility</b>	<b>Amount<sup>(a)</sup> (In billions)</b>	<b>Expiration Dates</b>	<b>Capacity Type</b>
<b>Exelon Corporate</b>			
Syndicated Revolver <sup>(b)</sup>	\$ 0.5	May 2019	Letters of credit and cash
<b>Generation</b>			
Syndicated Revolver	5.1	May 2019	Letters of credit and cash
Syndicated Revolver	0.2	August 2018	Letters of credit and cash
Bilateral	0.3	December 2015 and April 2016	Letters of credit and cash
Bilateral	0.1	January 2017	Letters of credit
Bilateral	0.1	October 2015	Letters of credit and cash
<b>ComEd</b>			
Syndicated Revolver	1.0	March 2019	Letters of credit and cash
<b>PECO</b>			
Syndicated Revolver <sup>(b)</sup>	0.6	May 2019	Letters of credit and cash
<b>BGE</b>			
Syndicated Revolver <sup>(b)</sup>	0.6	May 2019	Letters of credit and cash
<b>Total</b>	<b>\$ 8.5</b>		

(a) Excludes additional credit facility agreements for Generation, ComEd, PECO and BGE with aggregate commitments of \$50 million, \$34 million, \$34 million and \$5 million, respectively, arranged with minority and community banks located primarily within ComEd's, PECO's and BGE's service territories. These facilities expire on October 16, 2015. These facilities are solely utilized to issue letters of credit. As of March 31, 2015, letters of credit issued under these agreements for Generation, ComEd, PECO and BGE totaled \$7 million, \$16 million, \$21 million and \$1 million, respectively. Also, excludes the unsecured bridge credit facility of \$3.2 billion to support the PHI transaction discussed below.

(b) Syndicated revolvers include credit facility commitments of \$22 million, \$27 million and \$27 million for Exelon Corporate, PECO and BGE, respectively, which expire in August 2018.

As of March 31, 2015, there were no borrowings under the Registrants' credit facilities.



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Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit agreements bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon the particular Registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-based rate borrowings

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are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

**Credit Agreements**

In May 2014, concurrently and in connection with entering into the agreement to acquire PHI, Exelon entered into a credit facility to which the lenders committed to provide Exelon a 364-day senior unsecured bridge credit facility of \$7.2 billion to support the contemplated transaction and provide flexibility for timing of permanent financing. The bridge credit facility was subsequently reduced to \$3.2 billion as a result of the June 2014 \$1.15 billion Junior Subordinated note issuance and equity offering discussed below, as well as the net after-tax proceeds from generation asset divestitures during the second half of 2014. During the three months ended March 31, 2015, Exelon recorded \$11 million to interest expense in connection with the bridge facility. It is not currently expected that Exelon will be required to draw upon this credit facility.

**Long-Term Debt****Issuance of Long-Term Debt**

During the three months ended March 31, 2015, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Senior Unsecured Notes <sup>(a)</sup>	2.95%	January 15, 2020	\$ 750	Fund the optional redemption of Exelon's \$550 million, 4.550% Senior Notes and for general corporate purposes
Generation	AVSR DOE Nonrecourse Debt	2.293 - 2.559%	January 5, 2037	\$ 14	Antelope Valley solar development
Generation	Energy Efficiency Project Financing	3.71%	October 1, 2035	\$ 42	Funding to install energy conservation measures in Coleman, Florida
ComEd	Mortgage Bonds Series 118	3.70%	March 1, 2045	\$ 400	Refinance maturing mortgage bonds, repay a portion of ComEd's outstanding commercial paper obligations and for general corporate purposes

(a) In connection with the issuance of Senior Unsecured Notes, Exelon terminated floating-to-fixed interest rate swaps that had been designated as cash flow hedges. See Note 8 Derivative Financial Instruments for further information on the swap termination.

On April 1, 2015, Generation issued \$7 million of 2.464% AVSR DOE nonrecourse debt, maturing on January 5, 2037. The proceeds are used to fund the Antelope Valley Solar development.

On April 28, 2015, Generation issued \$18 million of 2.544% AVSR DOE nonrecourse debt, maturing on January 5, 2037. The proceeds are used to fund the Antelope Valley Solar development.

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

During the three months ended March 31, 2014, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	\$ 300	General corporate purposes
ComEd	First Mortgage Bonds Series 115	2.15%	January 15, 2019	\$ 300	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds Series 116	4.70%	January 15, 2044	\$ 350	Refinance maturing mortgage bonds and general corporate purposes

**Retirement and Redemptions of Current and Long-Term Debt**

During the three months ended March 31, 2015, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate(a)	Unsecured Notes	4.55%	June 15, 2015	\$ 550
Generation(a)	Unsecured Notes	4.55%	June 15, 2015	\$ 550
Generation	CEU Upstream Nonrecourse Debt	LIBOR + 2.25%	July 22, 2016	\$ 2
Generation	AVSR DOE Nonrecourse Debt	2.29%-3.56%	January 5, 2037	\$ 4
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	\$ 1
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	\$ 10
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	\$ 2

(a) As part of the 2012 Constellation merger, Exelon and subsidiaries of Generation assumed intercompany loan agreements that mirrored the terms and amounts of external obligations held by Exelon, resulting in intercompany notes payable at Generation and Exelon Corporate.

On April 1, 2015, BGE retired \$37 million aggregate principal of its 5.720% Rate Stabilization Bonds due 2017.

On April 6, 2015, Generation paid down \$2 million of principal and interest of its 2.29% 3.55% AVSR DOE Nonrecourse debt.

On April 15, 2015, ComEd retired \$260 million aggregate principal of its 4.700% First Mortgage Bonds, Series 101.

During the three months ended March 31, 2014, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	2003 Senior Notes	5.350%	January 15, 2014	\$ 500
Generation	Pollution Control Loan	4.100%	July 1, 2014	\$ 20
Generation	Continental Wind Nonrecourse Debt	6.000%	February 28, 2033	\$ 11
Generation	Kennett Square Capital Lease	7.830%	September 20, 2020	\$ 1
ComEd	Mortgage Bonds Series 110	1.630%	January 15, 2014	\$ 600
ComEd	Pollution Control Series 1994C	5.850%	January 15, 2014	\$ 17

**Junior Subordinated Notes**

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In June 2014, Exelon issued \$1.15 billion of junior subordinated notes in the form of 23 million equity units at a stated amount of \$50.00 per unit. Net proceeds from the issuance were \$1.11 billion, net of a \$35 million underwriter fee. The net proceeds are being used to finance a portion of the acquisition of PHI and for general corporate purposes. Each equity unit represents an undivided beneficial ownership interest in Exelon's 2.50% junior subordinated notes due in 2024 and a forward equity purchase contract which settles in 2017. The junior subordinated notes are expected to be remarketed in 2017.

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At the time of issuance, Exelon determined that the forward equity purchase contract had no value and therefore the entire \$1.15 billion of junior subordinated notes were allocated to debt and recorded within Long-term debt on Exelon's Consolidated Balance Sheet. Additionally, at the time of issuance, the present value of the contract payments of \$131 million were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments will be accreted to interest expense over the 3 year period ending in 2017 in Exelon's Consolidated Statement of Operations and Comprehensive Income. The Long-term debt recorded for the contract payments is considered a non-cash financing transaction that was excluded from Exelon's Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

For further information about the terms of the remarketing of the junior subordinated notes, see Note 13 Debt and Credit Agreements of the Exelon 2014 Form 10-K.

**10. Income Taxes (Exelon, Generation, ComEd, PECO and BGE)**

The effective income tax rate from continuing operations varies from the U.S. Federal statutory rate principally due to the following:

<b>For the Three Months Ended March 31, 2015</b>	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	2.6	2.7	5.0	1.2	5.3
Qualified nuclear decommissioning trust fund income	1.9	3.0			
Domestic production activities deduction	(2.2)	(3.4)			
Health care reform legislation					0.2
Amortization of investment tax credit, net deferred taxes	(0.9)	(1.4)	(0.3)	(0.1)	
Plant basis differences	(1.3)		(0.3)	(6.7)	(0.3)
Production tax credits and other credits	(1.8)	(2.8)			
Noncontrolling interest	(0.7)	(1.1)			
Other	0.4	(0.2)	0.2		0.2
Effective income tax rate	33.0%	31.8%	39.6%	29.4%	40.4%

<b>For the Three Months Ended March 31, 2014</b>	<b>Exelon</b>	<b>Generation(a)</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
U.S. Federal statutory rate	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) due to:					
State income taxes, net of Federal income tax benefit	(57.6)	9.7	5.5	1.2	5.2
Qualified nuclear decommissioning trust fund income	44.2	(4.6)			
Domestic production activities deduction	(27.8)	2.9			
Health care reform legislation	1.3		0.1		0.2
Amortization of investment tax credit, net deferred taxes	(18.0)	1.7	(0.3)	(0.1)	(0.2)
Plant basis differences	(31.4)		(0.6)	(8.7)	(0.6)
Production tax credits and other credits	(36.5)	3.8			
Noncontrolling interest					
Other	(47.7)	3.3	0.2	0.2	0.1
Effective income tax rate	(138.5)%	51.8%	39.9%	27.6%	39.7%

- (a) Generation recognized a loss before income taxes for the three months ended March 31, 2014. As a result, positive percentages represent an income tax benefit for Generation for the three months ended March 31, 2014.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****Accounting for Uncertainty in Income Taxes**

Exelon, Generation, ComEd, PECO, and BGE have \$1,282 million, \$733 million, \$147 million, \$0 million, and \$120 million, of unrecognized tax benefits as of March 31, 2015, respectively, and \$1,829 million, \$1,357 million, \$149 million, \$44 million, and \$0 million, of unrecognized tax benefits as of December 31, 2014, respectively. The unrecognized tax benefits as of March 31, 2015 reflect a decrease at Exelon, Generation, and PECO primarily attributable to the disallowed AmerGen claims discussed below. The unrecognized tax benefits as of March 31, 2015 reflect an increase at BGE and Generation attributable to a state income tax opportunity. A portion of the benefits associated with uncertain tax positions for utilities, if recognized, may be included in future base rates.

*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 disallowed AmerGen's claims. In early 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. On September 17, 2013, the Court granted the government's motion denying AmerGen's claims for refund. In the first quarter of 2014, Exelon filed an appeal of the decision to the United States Court of Appeals for the Federal Circuit. On March 11, 2015, the Federal Circuit affirmed the lower court's decision to deny AmerGen's claims for refund. Exelon will not be pursuing further appeals with respect to this issue and, as a result, has reduced its total unrecognized tax benefits by \$661 million. This change in unrecognized tax benefits had no impact on Exelon's or Generation's effective tax rate.

**Reasonably possible the total amount of unrecognized tax benefits could significantly increase or decrease within 12 months after the reporting date***Settlement of Income Tax Audits*

As of March 31, 2015, Exelon, Generation, and BGE have approximately \$345 million, \$225 million, and \$120 million of unrecognized state tax benefits that could significantly decrease within the 12 months after the reporting date as a result of completing audits, potential settlements, and expected statute of limitation expirations. Of the above unrecognized tax benefits, Exelon and Generation have \$225 million that, if recognized, would decrease the effective tax rate. The unrecognized tax benefit related to BGE, if recognized, may be included in future base rates and that portion would have no impact to the effective tax rate.

**Other Income Tax Matters***Like-Kind Exchange*

Exelon, through its ComEd subsidiary, took a position on its 1999 income tax return to defer approximately \$1.2 billion of tax gain on the sale of ComEd's fossil generating assets. The gain was deferred by reinvesting a portion of the proceeds from the sale in qualifying replacement property under the like-kind exchange provisions of the IRC. The like-kind exchange replacement property purchased by Exelon included interests in three municipal-owned electric generation facilities which were properly leased back to the municipalities. The IRS disagreed with this position and asserted that the entire gain of approximately \$1.2 billion was taxable in 1999.

Exelon has been unable to reach agreement with the IRS regarding the dispute over the like-kind exchange position. The IRS has asserted that the Exelon purchase and leaseback transaction is substantially similar to a

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

leasing transaction, known as a SILO, which the IRS does not respect as the acquisition of an ownership interest in property. A SILO is a listed transaction that the IRS has identified as a potentially abusive tax shelter under guidance issued in 2005. Accordingly, the IRS has asserted that the sale of the fossil plants followed by the purchase and leaseback of the municipal owned generation facilities does not qualify as a like-kind exchange and the gain on the sale is fully subject to tax. The IRS has also asserted a penalty of approximately \$90 million for a substantial understatement of tax.

Exelon disagrees with the IRS and continues to believe that its like-kind exchange transaction is not the same as or substantially similar to a SILO. Although Exelon has been and remains willing to settle the disagreement on terms commensurate with the hazards of litigation, Exelon does not believe a settlement is possible. Because Exelon believed, as of December 31, 2012, that it was more-likely-than-not that Exelon would prevail in litigation, Exelon and ComEd had no liability for unrecognized tax benefits with respect to the like-kind exchange position.

On January 9, 2013, the U.S. Court of Appeals for the Federal Circuit reversed the U.S. Court of Federal Claims and reached a decision for the government in Consolidated Edison v. United States. The Court disallowed Consolidated Edison's deductions stemming from its participation in a LILO transaction that the IRS also has characterized as a tax shelter.

In accordance with applicable accounting standards, Exelon is required to assess whether it is more-likely-than-not that it will prevail in litigation. Exelon continues to believe that its transaction is not a SILO and that it has a strong case on the merits. However, in light of the Consolidated Edison decision and Exelon's current determination that settlement is unlikely, Exelon has concluded that subsequent to December 31, 2012, it is no longer more-likely-than-not that its position will be sustained. As a result, in the first quarter of 2013 Exelon recorded a non-cash charge to earnings of approximately \$265 million, which represents the amount of interest expense (after-tax) and incremental state income tax expense for periods through March 31, 2013 that would be payable in the event that Exelon is unsuccessful in litigation. Of this amount, approximately \$170 million was recorded at ComEd. Exelon intends to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts on ComEd's equity. As such, ComEd recorded on its consolidated balance sheet as of March 31, 2013, a \$172 million receivable and non-cash equity contributions from Exelon. Exelon and ComEd will continue to accrue interest on the unpaid tax liabilities related to the uncertain tax position, and the charges arising from future interest accruals are not expected to be material to the annual operating earnings of Exelon or ComEd. In addition, ComEd will continue to record non-cash equity contributions from Exelon in the amount of the net after-tax interest charges attributable to ComEd in connection with the like-kind exchange position. Exelon continues to believe that it is unlikely that the IRS's assertion of penalties will ultimately be sustained and therefore no liability for the penalty has been recorded.

On September 30, 2013, the IRS issued a notice of deficiency to Exelon for the like-kind exchange position. Exelon filed a petition on December 13, 2013 to initiate litigation in the United States Tax Court and the trial has been scheduled for August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. The litigation could take three to five years including appeals, if necessary. Decisions in the Tax Court are not controlled by the Federal Circuit's decision in Consolidated Edison.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of March 31, 2015 may be as much as \$810 million, of which approximately \$310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.



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In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of \$335 million. The termination will result in a 2014 tax payment of approximately \$285 million by Exelon, including approximately \$155 million by ComEd representing the remaining gain deferred pursuant to the like-kind exchange transaction. In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, Exelon will be required to pay the full amount of tax and after-tax interest discussed in the preceding paragraph but will ultimately be entitled to a refund of the 2014 tax payment.

**11. Nuclear Decommissioning (Exelon and Generation)*****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 for financial accounting and reporting purposes, Generation uses a probability-weighted, discounted cash flow model which, on a unit-by-unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on decommissioning cost studies, cost escalation rates, probabilistic cash flow models and discount rates. Generation generally updates its ARO annually during the third quarter, unless circumstances warrant more frequent updates, based on its review of updated cost studies and its annual evaluation of cost escalation factors and probabilities assigned to various scenarios.

The following table provides a rollforward of the nuclear decommissioning ARO reflected on Exelon's and Generation's Consolidated Balance Sheets from December 31, 2014 to March 31, 2015:

Nuclear decommissioning ARO at December 31, 2014 <sup>(a)</sup>	\$ 6,961
Net increase due to changes in, and timing of, estimated future cash flows <sup>(b)</sup>	55
Accretion expense	94
Nuclear decommissioning ARO at March 31, 2015 <sup>(a)</sup>	\$ 7,110

(a) Includes \$8 million as the current portion of the ARO at March 31, 2015 and December 31, 2014, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

(b) Represents a purchase accounting adjustment to the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 6 Investment in Constellation Energy Nuclear Group, LLC for additional information.

***Nuclear Decommissioning Trust Fund Investments***

NDT funds have been established for each generating station unit to satisfy Generation's nuclear decommissioning obligations. Generally, 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 Generation's nuclear units have been funded with amounts collected from the previous owners and their respective utility customers. PECO is authorized to collect funds, in revenues, for decommissioning the former PECO nuclear plants through regulated rates, and these collections are scheduled through the operating lives of the former PECO plants. The amounts collected from PECO customers are remitted to Generation and deposited into the NDT funds for the unit for which funds are collected. Every five years, PECO files a rate adjustment with the PAPUC that reflects PECO's calculations of the estimated amount needed to decommission each of the former PECO units based on updated fund balances and estimated decommissioning costs. The rate adjustment is used to determine the amount collectible from PECO customers. The most recent rate adjustment occurred on January 1, 2013, and the effective rates currently yield annual



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

collections of approximately \$24 million. The next five-year adjustment is expected to be reflected in rates charged to PECO customers effective January 1, 2018. Aside from the former PECO units, Generation does not currently collect any amounts, nor is there any mechanism by which Generation can seek to collect additional amounts, from utility customers. Apart from the contributions made to the NDT funds from amounts previously collected from ComEd and currently collected from 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, with the exception of a shortfall for the current decommissioning activities at Zion Station, where certain decommissioning activities have been transferred to a third party (see Zion Station Decommissioning below) and the CENG units, where any shortfall is required to be funded by both Generation and EDF. Generation, through PECO, 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, and likewise Generation, will not be allowed to collect amounts associated with the first \$50 million of any shortfall of trust funds, compared to decommissioning costs, as well as 5% of any additional shortfalls, on an aggregate basis for all former PECO units. The initial \$50 million and up to 5% of any additional shortfalls would be borne by Generation. No recourse exists to collect additional amounts for any of Generation's other nuclear units, including the CENG units. With respect to the former ComEd and PECO units, any funds remaining in the NDTs after all 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 Generation's other nuclear units, Generation retains any funds remaining after decommissioning. However, in connection with CENG's acquisition of the Nine Mile Point and Ginna plants and settlements with certain regulatory agencies, CENG is subject to certain conditions pertaining to nuclear decommissioning trust funds that, if met, could possibly result in obligations to make payments to certain third parties (clawbacks). For Nine Mile Point and Ginna, the clawback provisions are triggered only in the event that the required decommissioning activities are discontinued or not started or completed in a timely manner. In the event that the clawback provisions are triggered for Nine Mile Point, then, depending upon the triggering event, an amount equal to 50% of the total amount withdrawn from the funds for non-decommissioning activities or 50% of any excess funds in the trust funds above the amounts required for decommissioning (including spent fuel management and decommissioning) is to be paid to the Nine Mile Point sellers. In the event that the clawback provisions are triggered for Ginna, then an amount equal to any estimated cost savings realized by not completing any of the required decommissioning activities is to be paid to the Ginna sellers. Generation expects to comply with applicable regulations and timely commence and complete all required decommissioning activities.

At March 31, 2015 and December 31, 2014, Exelon and Generation had NDT fund investments totaling \$10,712 million and \$10,537 million, respectively.

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The following table provides unrealized gains on NDT funds for the three months ended March 31, 2015 and 2014:

		<b>Exelon and Generation</b>	
		<b>Three Months Ended March 31,</b>	
		<b>2015</b>	<b>2014</b>
Net unrealized gains on decommissioning trust funds	Regulatory Agreement Units <sup>(a)</sup>	\$ 48	\$ 61
Net unrealized gains on decommissioning trust funds	Non-Regulatory Agreement Units <sup>(b)(c)</sup>	40	13

- (a) Net unrealized 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 \$10 million of net unrealized gains related to the Zion Station pledged assets for the three months ended March 31, 2015 and 2014. Net unrealized 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) Net unrealized gains related to Generation's NDT funds 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 are eliminated within Other, net in Exelon's and Generation's Consolidated Statement of Operations and Comprehensive Income.

Refer to Note 3 Regulatory Matters and Note 25 Related Party Transactions of the Exelon 2014 Form 10-K 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.

***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. See Note 15 Asset Retirement Obligations of the Exelon 2014 Form 10-K for information regarding the specific treatment of assets, including NDT funds, and decommissioning liabilities transferred in the transaction.

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's 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 for Zion Station decommissioning in Generation's 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. Generation has retained its obligation for the SNF. Following ZionSolutions' completion of its contractual obligations and transfer of the NRC license

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

to Generation, Generation will store the SNF at Zion Station until it is transferred to the DOE for ultimate disposal, and will complete all remaining decommissioning activities associated with the SNF dry storage facility. Generation has a liability of approximately \$87 million, which is included within the nuclear decommissioning ARO at March 31, 2015. Generation also has retained NDT assets to fund its obligation to maintain the SNF at Zion Station until transfer to the DOE and to complete all remaining decommissioning activities for the SNF storage facility. Any shortage of funds necessary to maintain the SNF and decommission the SNF storage facility is ultimately required to be funded by Generation. Any Zion Station NDT funds remaining after the completion of all decommissioning activities will be returned to ComEd customers in accordance with the applicable orders. The following table provides the pledged assets and payables to ZionSolutions, and withdrawals by ZionSolutions at March 31, 2015 and December 31, 2014:

	Exelon and Generation	
	March 31, 2015	December 31, 2014
Carrying value of Zion Station pledged assets	\$ 308	\$ 319
Payable to Zion Solutions <sup>(a)</sup>	281	292
Current portion of payable to Zion Solutions <sup>(b)</sup>	145	137
Cumulative withdrawals by Zion Solutions to pay decommissioning costs	687	666

(a) Excludes a liability recorded within Exelon's and 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.

(b) Included in Other current liabilities within Exelon's and Generation's Consolidated Balance Sheets.

***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.

Generation filed its biennial decommissioning funding status report with the NRC on March 31, 2015. This report reflects the status of decommissioning funding assurance as of December 31, 2014. Due to increased cost estimates received in the second half of 2014, Braidwood Unit 1, Braidwood Unit 2, and Byron Unit 2 did not meet the NRC's minimum funding assurance criteria as of December 31, 2014. NRC guidance provides licensees with two years or by the time of submitting the next biennial report (on or before March 31, 2017) to resolve funding assurance shortfalls. During this period, Generation will monitor funding assurance and new developments, including the impact of a 20-year license renewal for Braidwood and Byron, to assess the status of funding assurance and to take steps, if necessary, to address any funding shortfall on these funds on or before March 31, 2017.

**12. Retirement Benefits (Exelon, Generation, ComEd, PECO and BGE)**

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

***Defined Benefit Pension and Other Postretirement Benefits***

During the first quarter of 2015, Exelon received an updated valuation of its pension and other postretirement benefit obligations to reflect actual census data as of January 1, 2015. This valuation resulted in an increase to the pension obligation of \$45 million and an increase to the other postretirement benefit obligation of



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\$57 million. Additionally, accumulated other comprehensive loss increased by approximately \$27 million (after tax), regulatory assets increased by approximately \$48 million, and regulatory liabilities decreased by approximately \$11 million.

The majority of the 2015 pension benefit cost for Exelon-sponsored plans is calculated using an expected long-term rate of return on plan assets of 7.00% and a discount rate of 3.94%. The majority of the 2015 other postretirement benefit cost is calculated using an expected long-term rate of return on plan assets of 6.46% for funded plans and a discount rate of 3.92%. A portion of the net periodic benefit cost is capitalized within the Consolidated Balance Sheets. The following table presents the components of Exelon's net periodic benefit costs, prior to any capitalization, for the three months ended March 31, 2015 and 2014.

	Pension Benefits		Other Postretirement Benefits	
	Three Months Ended		Three Months Ended	
	March 31,		March 31,	
	2015 <sup>(a)</sup>	2014 <sup>(a)</sup>	2015 <sup>(a)</sup>	2014 <sup>(a)</sup>
Service cost	\$ 82	\$ 69	\$ 30	\$ 33
Interest cost	178	183	42	55
Expected return on assets	(257)	(241)	(38)	(38)
Amortization of:				
Prior service cost (benefit)	3	3	(43)	(4)
Actuarial loss	143	105	20	8
Net periodic benefit cost	\$ 149	\$ 119	\$ 11	\$ 54

(a) For the three months ended March 31, 2015, the cost for pension benefits and other postretirement benefits related to CENG were \$3 million and \$3 million, respectively. CENG is not included in the 2014 amounts.

The amounts below represent Generation's, ComEd's, PECO's, BGE's and BSC's allocated portion of the pension and postretirement benefit plan costs, which were included in Property, plant and equipment within the respective Consolidated Balance Sheets and Operating and maintenance expense within the Consolidated Statement of Operations and Comprehensive Income during the three months ended March 31, 2015 and 2014.

Pension and Other Postretirement Benefit Costs	Three Months Ended March 31,	
	2015	2014
Generation <sup>(a)</sup>	\$ 67	\$ 75
ComEd	52	56
PECO	10	12
BGE	17	16
BSC <sup>(b)</sup>	14	14

(a) For the three months ended March 31, 2015, the cost for pension benefits and other postretirement benefits related to CENG were \$3 million and \$3 million, respectively. CENG is not included in the 2014 amounts.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These amounts are not included in the Generation, ComEd, PECO or BGE amounts above.





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

**Defined Contribution Savings Plans**

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three months ended March 31, 2015 and 2014:

Savings Plan Matching Contributions	Three Months Ended March 31,	
	2015	2014
Exelon <sup>(a)</sup>	\$ 22	\$ 29
Generation <sup>(a)</sup>	13	14
ComEd	5	7
PECO	1	2
BGE	2	3
BSC <sup>(b)</sup>	1	3

(a) Includes \$2 million related to CENG for the three months ended March 31, 2015. CENG is not included in the 2014 amounts.

(b) These amounts primarily represent amounts billed to Exelon's subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

**13. Severance (Exelon, Generation, ComEd, PECO and BGE)**

The Registrants have an ongoing severance plan under which, in general, the longer an employee worked prior to termination the greater the amount of severance benefits. The Registrants record a liability and expense or regulatory asset for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan (one-time termination benefits), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

**Ongoing Severance Plans**

The Registrants provide severance, health and welfare benefits under Exelon's ongoing severance benefit plans to terminated employees in the normal course of business, which were not directly related to the merger with Constellation or with the integration of CENG. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the three months ended March 31, 2015 and 2014, the Registrants recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

Severance Benefits	Exelon	Generation	ComEd	PECO	BGE
Severance charges 2015	\$ 20	\$ 20	\$	\$	\$
Severance charges 2014	\$ 4	\$ 4	\$	\$	\$

The severance liability balances associated with these ongoing severance benefits as of March 31, 2015 and December 31, 2014 are not material.



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

**14. Changes in Accumulated Other Comprehensive Income (Exelon, Generation, and PECO)**

The following tables present changes in accumulated other comprehensive income (loss) (AOCI) by component for the three months ended March 31, 2015 and 2014:

	Gains and (Losses) on Hedging Activity	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
<b>Three Months Ended March 31, 2015</b>						
<b>Exelon<sup>(a)</sup></b>						
Beginning balance	\$ (28)	\$ 3	\$ (2,640)	\$ (19)	\$	\$ (2,684)
OCI before reclassifications	(11)		(26)	(12)		(49)
Amounts reclassified from AOCI <sup>(b)</sup>	17		43			60
Net current-period OCI	6		17	(12)		11
Ending balance	\$ (22)	\$ 3	\$ (2,623)	\$ (31)	\$	\$ (2,673)
<b>Generation<sup>(a)</sup></b>						
Beginning balance	\$ (18)	\$ 1	\$	\$ (19)	\$	\$ (36)
OCI before reclassifications	(6)			(12)		(18)
Amounts reclassified from AOCI <sup>(b)</sup>	1					1
Net current-period OCI	(5)			(12)		(17)
Ending balance	\$ (23)	\$ 1	\$	\$ (31)	\$	\$ (53)
<b>PECO<sup>(a)</sup></b>						
Beginning balance	\$	\$ 1	\$	\$	\$	\$ 1
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>						
Net current-period OCI						
Ending balance	\$	\$ 1	\$	\$	\$	\$ 1

(a) All amounts are net of tax. Amounts in parentheses represent a decrease in accumulated other comprehensive income.

(b) See tables following changes in accumulated other comprehensive income tables for details about these reclassifications.



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Three Months Ended March 31, 2014	Gains and (Losses) on Hedging Activity	Unrealized Gains and (Losses) on Marketable Securities	Pension and Non-Pension Postretirement Benefit Plan Items	Foreign Currency Items	AOCI of Equity Investments	Total
<b>Exelon<sup>(a)</sup></b>						
Beginning balance	\$ 120	\$ 2	\$ (2,260)	\$ (10)	\$ 108	\$ (2,040)
OCI before reclassifications	(1)		(13)	(5)	11	(8)
Amounts reclassified from AOCI <sup>(b)</sup>	(24)		35		1	12
Net current-period OCI	(25)		22	(5)	12	4
Ending balance	\$ 95	\$ 2	\$ (2,238)	\$ (15)	\$ 120	\$ (2,036)
<b>Generation<sup>(a)</sup></b>						
Beginning balance	\$ 114	\$ 2		\$ (10)	\$ 108	\$ 214
OCI before reclassifications	(1)	(3)		(5)	11	2
Amounts reclassified from AOCI <sup>(b)</sup>	(24)				1	(23)
Net current-period OCI	(25)	(3)		(5)	12	(21)
Ending balance	\$ 89	\$ (1)		\$ (15)	\$ 120	\$ 193
<b>PECO<sup>(a)</sup></b>						
Beginning balance	\$	\$ 1		\$	\$	\$ 1
OCI before reclassifications						
Amounts reclassified from AOCI <sup>(b)</sup>						
Net current-period OCI						
Ending balance	\$	\$ 1		\$	\$	\$ 1

(a) All amounts are net of tax. Amounts in parentheses represent a decrease in accumulated other comprehensive income.

(b) See tables following changes in accumulated other comprehensive income tables for details about these reclassifications.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net income during the three months ended March 31, 2015 and 2014. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the three months ended March 31, 2015 and 2014.

**Three Months Ended March 31, 2015**

Details about AOCI components	Items reclassified out of AOCI <sup>(a)</sup>		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains (losses) on hedging activity			
Terminated interest rate swaps <sup>(c)</sup>	\$ (26)	\$	Other, net
Energy related hedges	2	2	Operating revenues
Other cash flow hedges	(3)	(3)	Interest expense
	(27)	(1)	Total before tax
	10		Tax benefit
	\$ (17)	\$ (1)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs <sup>(b)</sup>	\$ 19	\$	
Actuarial losses <sup>(b)</sup>	(90)		
	(71)		Total before tax
	28		Tax benefit
	\$ (43)	\$	Net of tax
Total Reclassifications for the period	\$ (60)	\$ (1)	Net of Tax

**Three months ended March 31, 2014**

Details about AOCI components	Items reclassified out of AOCI <sup>(a)</sup>		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains on hedging activity			
Energy related hedges	\$ 39	\$ 39	Operating revenues
	39	39	Total before tax
	(15)	(15)	Tax (expense)
	\$ 24	\$ 24	Net of tax

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Amortization of pension and other postretirement benefit

plan items

Prior service costs <sup>(b)</sup>	\$ (2)	\$	
Actuarial losses <sup>(b)</sup>	(56)		

(58)		Total before tax
23		Tax benefit

\$ (35)	\$	Net of tax
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Equity investments

Capital activity	\$ (1)	\$ (1)	Equity in losses of unconsolidated affiliates
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(1)	(1)	Total before tax
		Tax benefit

\$ (1)	\$ (1)	Net of tax
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Total reclassifications for the period	\$ (12)	\$ 23	Net of Tax
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**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

- (a) All amounts are net of tax. Amounts in parentheses represent a decrease in net income.
- (b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 12 Retirement Benefits for additional details).
- (c) In January 2015, in connection with Generation's \$750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, \$26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,	
	2015	2014
<b>Exelon</b>		
Pension and non-pension postretirement benefit plans:		
Prior service benefit reclassified to periodic benefit cost	\$ 8	\$ (1)
Actuarial gain (loss) reclassified to periodic cost	(35)	(23)
Pension and non-pension postretirement benefit plans valuation adjustment	17	7
Change in unrealized gain (loss) on cash flow hedges	(2)	18
Change in unrealized income on equity investments		(7)
Total	\$ (12)	\$ (6)
<b>Generation</b>		
Change in unrealized gain (loss) on cash flow hedges	\$ 5	\$ 19
Change in unrealized income on equity investments		(7)
Change in marketable securities		(2)
Total	\$ 5	\$ 10

**15. Common Stock (Exelon, Generation, ComEd, PECO and BGE)****Equity Securities Offering**

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of \$35 per share. In connection with such offering, Exelon entered into forward sale agreements requiring Exelon to settle the transaction prior to October 29, 2015. No amounts have or will be recorded in Exelon's consolidated financial statements with respect to the equity offering until settlement of the forward sale agreements occurs. Based on the average stock price for the quarter ended March 31, 2015, if Exelon had elected to net settle the contract, Exelon would have been required to issue approximately 2.5 million shares at a forward price of \$33.21. If Exelon elects to cash settle the contract, the transaction costs will be recorded as a charge to earnings in the period in which it becomes probable that Exelon will cash settle. Otherwise, all transaction costs will be reflected as a reduction to the value of the common stock issued in Exelon's Consolidated Balance Sheet. The net proceeds received upon settlement are expected to be used to finance a portion of the proposed acquisition of PHI and for general corporate purposes. Until settlement, earnings per share dilution resulting from the forward sales agreement, if any, will be determined under the treasury stock method. For further information on the options Exelon has to settle the transaction, refer to note 19 Common Stock of the Exelon 2014 Form 10-K



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Concurrent with the forward equity transaction, Exelon also issued \$1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 9 Debt and Credit Agreements for further information on the equity units.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)****16. Earnings Per Share and Equity (Exelon)***Earnings per Share (Exelon)*

Diluted earnings per share is calculated by dividing Net income attributable to common shareholders by the weighted average number of shares of common stock outstanding adjusted to include the potentially dilutive effect of stock options, performance share awards and restricted stock outstanding under Exelon's LTIPs. 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 (in millions) used in calculating diluted earnings per share:

	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
Net income attributable to common shareholders	\$ 693	\$ 90
Average common shares outstanding - basic	862	858
Potentially dilutive effect of stock options, performance share awards and restricted stock	5	3
Average common shares outstanding - diluted	867	861

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 15 million and 18 million for the three months ended March 31, 2015 and 2014, respectively. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was less than 1 million for the three months ended March 31, 2015 since issuance. Additionally, there were no forward units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the three months ended March 31, 2015 and since issuance. Refer to Note 15 - Common Stock for further information regarding the equity units and equity forward units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of \$2.3 billion as of March 31, 2015. In 2008, Exelon management decided to defer indefinitely any share repurchases.

**17. Commitments and Contingencies (Exelon, Generation, ComEd, PECO and BGE)**

The following is an update to the current status of commitments and contingencies set forth in Note 22 of the Exelon 2014 Form 10-K.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Commitments****Energy Commitments**

As of March 31, 2015, Generation's commitments relating to its purchases from unaffiliated utilities and others of energy, capacity, transmission rights and RECs, are as indicated in the following table:

	Net Capacity Purchases <sup>(a)</sup>	REC Purchases <sup>(b)</sup>	Transmission Rights Purchases <sup>(c)</sup>	Total
2015	\$ 317	\$ 124	\$ 13	\$ 454
2016	287	258	15	560
2017	219	153	15	387
2018	109	52	16	177
2019	113	9	16	138
Thereafter	276	1	35	312
Total	\$ 1,321	\$ 597	\$ 110	\$ 2,028

- (a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation's expected payments under these arrangements at March 31, 2015, net of fixed capacity payments expected to be received (capacity offsets) by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of March 31, 2015, capacity offsets were \$107 million, \$133 million, \$136 million, \$137 million, \$138 million, and \$591 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.
- (b) The table excludes renewable energy purchases that are contingent in nature.
- (c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd's, PECO's and BGE's electric supply procurement, curtailment services, REC and AEC purchase commitments, as applicable, as of March 31, 2015 are as follows:

	Total	Expiration within					2020 and beyond
		2015	2016	2017	2018	2019	
ComEd							
Electric supply procurement <sup>(a)(b)</sup>	\$ 473	\$ 182	\$ 151	\$ 140	\$	\$	\$
Renewable energy and RECs <sup>(c)</sup>	1,498	56	76	77	78	84	1,127
PECO							
Electric supply procurement <sup>(d)</sup>	832	532	268	32			
AECs <sup>(e)</sup>	13	2	2	2	2	2	3
BGE							
Electric supply procurement <sup>(f)</sup>	1,074	538	448	88			
Curtailment services <sup>(g)</sup>	105	30	34	29	12		

- (a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2018. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. As of March 31, 2015, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017.
- (b) Excludes electric supply commitments associated with the Spring 2015 procurement process approved by the ICC on April 1, 2015, for the years 2015-2018 in the amount of \$179 million, \$112 million, \$23 million, and \$21 million, respectively.

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

- (c) Primarily related to ComEd 20-year contracts for renewable energy and RECs that began in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.
- (d) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2015 and 2017. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 Regulatory Matters for additional information.
- (e) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information.
- (f) BGE entered into various contracts for the procurement of electricity that expire between 2015 through 2017. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3 Regulatory Matters of the Exelon 2014 10-K for additional information.
- (g) BGE has entered into various contracts with curtailment services providers related to transactions in PJM's capacity market. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K 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. Since the second quarter of 2014, 100% of CENG's nuclear fuel commitments are disclosed within the Generation line below, since CENG is now fully consolidated by Generation. PECO and BGE have commitments to purchase natural gas related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of March 31, 2015, these net commitments were as follows:

	Total	2015	2016	Expiration within			2020 and beyond
				2017	2018	2019	
Generation	\$ 8,479	\$ 1,015	\$ 1,145	\$ 1,151	\$ 987	\$ 869	\$ 3,312
PECO	392	109	104	61	34	13	71
BGE	614	82	87	74	64	61	246

**Other Purchase Obligations**

The Registrants' other purchase obligations as of March 31, 2015, which primarily represent commitments for services, materials and information technology, are as follows:

	Total	2015	2016	Expiration within			2020 and beyond
				2017	2018	2019	
Exelon	\$ 840	\$ 258	\$ 279	\$ 152	\$ 38	\$ 30	\$ 83
Generation <sup>(a)</sup>	364	123	81	43	31	23	63
ComEd <sup>(b)</sup>	152	53	82	2	2	2	11
PECO <sup>(b)</sup>	11	5	6				
BGE <sup>(b)</sup>	313	77	110	107	5	5	9

- (a) Purchase obligations do not include commitments related to construction contracts. See Construction Commitments section below for additional information.
- (b) Purchase obligations include commitments related to smart meter installation. See Note 5 Regulatory Matters for additional information.



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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

***Construction Commitments***

Generation's ongoing investments in renewables development and new natural gas construction illustrates Generation's growth strategy to provide for diversification opportunities while leveraging its expertise and strengths.

On July 26, 2013, Generation executed an engineering procurement and construction contract to expand its Perryman, Maryland generation site with at least 120 MW of new natural gas-fired generation. The remaining commitment is approximately \$17 million under the contract and achievement of commercial operations is expected in 2015. This project will satisfy a portion of Exelon's commitment to Maryland. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

During the third and fourth quarter of 2014, Generation executed contracts associated with the construction of new combined-cycle gas turbine units in Texas. The remaining commitment is approximately \$816 million under these contracts and achievement of commercial operations is expected in 2017.

During the fourth quarter of 2014, Generation executed contracts associated with the construction of the 30 MW Fair Wind project in western Maryland. The remaining commitment is approximately \$26 million under these contracts and achievement of commercial operations is expected in 2015. This project will satisfy a portion of Exelon's 125 MW Tier I land-based renewables commitment made to Maryland. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

During the fourth quarter of 2014, Generation executed contracts associated with the construction of the 78 MW Sendero Wind project in southern Texas. The remaining commitment is approximately \$34 million under these contracts and achievement of commercial operations is expected in 2015.

Refer to Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for information on investment programs associated with regulatory mandates, such as ComEd's Infrastructure Investment Plan under EIMA, PECO's Smart Meter Procurement and Installation Plan and BGE's comprehensive smart grid initiative.

***Constellation Merger Commitments***

In February 2012, the MDPSC issued an Order approving the Exelon and Constellation merger. As part of the MDPSC Order, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately \$1 billion.

The direct investment estimate includes \$95 million to \$120 million relating to the construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. Generation's total commitments under the lease agreement are \$0 million, \$5 million, \$12 million, \$13 million, \$13 million, and \$285 million, related to 2015, 2016, 2017, 2018, 2019 and thereafter.

The direct investment commitment also includes \$600 million to \$650 million relating to Exelon and Generation's development or assistance in the development of 285 - 300 MWs of new generation in Maryland,

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

which is expected to be completed over a period of 10 years. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation now believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax \$44 million loss contingency related to this generation development commitment which is included in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income. While this \$44 million loss contingency represents Generation's best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately \$105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for additional information regarding the Constellation merger commitments.

**Equity Investment Commitments**

As part of Generation's recent investments in technology development, Generation has entered into equity purchase agreements that include commitments to purchase additional equity through incremental payments. The additional equity is provided by the agreements to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately \$20 million of in-kind services. As of March 31, 2015, Generation's estimated commitment relating to its equity purchase agreements, including the in-kind services contributions, is anticipated to be as follows:

	<b>Total</b>
2015	\$ 77
2016	37
2017	19
2018	14
<b>Total</b>	<b>\$ 147</b>

**Contingencies****Commercial Commitments**

The Registrants' commercial commitments as of March 31, 2015, representing commitments potentially triggered by future events were as follows:

	<b>Exelon</b>	<b>Generation</b>	<b>ComEd</b>	<b>PECO</b>	<b>BGE</b>
Letters of credit (non-debt) <sup>(a)</sup>	\$ 1,740	\$ 1,673	\$ 18	\$ 22	\$ 1
Guarantees	5,453 <sup>(b)</sup>	2,678 <sup>(c)</sup>	202 <sup>(d)</sup>	196 <sup>(e)</sup>	263 <sup>(f)</sup>
Nuclear insurance premiums <sup>(g)</sup>	3,014	3,014			
Underwriters discount <sup>(h)</sup>	60				
<b>Total commercial commitments</b>	<b>\$ 10,267</b>	<b>\$ 7,365</b>	<b>\$ 220</b>	<b>\$ 218</b>	<b>\$ 264</b>





**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

- (a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
- (b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was \$642 million at March 31, 2015, which represents the total amount Exelon could be required to fund based on March 31, 2015 market prices.
- (c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts. The estimated net exposure for obligations under commercial transactions covered by these guarantees was \$429 million at March 31, 2015, which represents the total amount Generation could be required to fund based on March 31, 2015 market prices.
- (d) Primarily reflects full and unconditional guarantees of \$200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.
- (e) Primarily reflects full and unconditional guarantees of \$178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.
- (f) Primarily reflects full and unconditional guarantees of \$250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.
- (g) Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, 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.
- (h) Represents the underwriters discount for Exelon's forward equity transaction. See Note 15 Common Stock for further details of the equity securities offering.

***Nuclear Insurance (Exelon and Generation)***

Generation is subject to liability, property damage and other risks associated with major incidents at any of its nuclear stations, including the CENG nuclear stations. Generation has mitigated its financial exposure to these risks through insurance and other industry risk-sharing provisions.

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 March 31, 2015, the current liability limit per incident was \$13.6 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 September 10, 2013. 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 March 31, 2015, 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 \$13.2 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 \$127.3 million, payable at no more than \$19 million per reactor per incident per year. Exelon's maximum liability per incident is approximately \$2.7 billion, including CENG's related liability.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the \$13.6 billion limit for a single incident.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

As part of the execution of the NOSA on April 1, 2014, Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation's obligations under this indemnity. See Note 6 Investment in Constellation Energy Nuclear Group, LLC for additional information on Generation's operations relating to CENG.

Generation is required each year to report to the NRC the current levels and sources of property insurance that demonstrates Generation possesses sufficient financial resources to stabilize and decontaminate a reactor and reactor station site in the event of an accident. The property insurance maintained for each facility is currently provided through insurance policies purchased from NEIL, an industry mutual insurance company of which Generation is a member.

NEIL provides all risk property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. 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. 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.

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.

**Environmental Issues**

**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.

ComEd, PECO and BGE have identified sites where former MGP activities have or may have resulted in actual site contamination. For almost all of these sites, there are additional PRPs that may share responsibility for the ultimate remediation of each location.

ComEd has identified 42 sites, 17 of which the remediation has been completed and approved by the Illinois EPA or the U.S. EPA and 25 that are currently under some degree of active study and/or remediation. ComEd expects the majority of the remediation at these sites to continue through at least 2019.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

PECO has identified 26 sites, 16 of which have been remediated in accordance with applicable PA DEP regulatory requirements. The remaining 10 sites are currently under some degree of active study and/or remediation. PECO expects the majority of the remediation at these sites to continue through at least 2021.

BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor's acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. An investigation of an additional gas purification site was completed during the first quarter of 2015 at the direction of the MDE. BGE has established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Management is unable to estimate the maximum exposure of potential remediation efforts at this time, which may have a material impact on BGE's results of operations and cash flows.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. ComEd and PECO have recorded regulatory assets for the recovery of these costs. See Note 5 Regulatory Matters for additional information regarding the associated regulatory assets. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. BGE has not established a regulatory asset for the costs associated with the gas purification site as of March 31, 2015.

As of March 31, 2015 and December 31, 2014, the Registrants had accrued the following undiscounted amounts for environmental liabilities in other current liabilities and other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

	<b>Total Environmental Investigation and Remediation Reserve</b>	<b>Portion of Total Related to MGP Investigation and Remediation</b>
<b>March 31, 2015</b>		
Exelon	\$ 340	\$ 272
Generation	62	
ComEd	231	228
PECO	44	42
BGE	3	2

	<b>Total Environmental Investigation and Remediation Reserve</b>	<b>Portion of Total Related to MGP Investigation and Remediation</b>
<b>December 31, 2014</b>		
Exelon	\$ 347	\$ 277
Generation	63	
ComEd	238	235
PECO	45	42
BGE	1	

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.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

***Water Quality***

***Groundwater Contamination.*** In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a \$1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Generation's remaining groundwater contamination reserve was \$13 million at both March 31, 2015 and December 31, 2014. In addition, a private party asserted claims relating to groundwater contamination. In February 2014, Generation settled these private party claims for an amount that was not material to the financial condition of Generation.

***Air Quality***

***Notices and Finding of Violations and Midwest Generation Bankruptcy.*** In December 1999, ComEd sold several generating stations to Midwest Generation, LLC (Midwest Generation), a subsidiary of Edison Mission Energy (EME). Under the terms of the sale agreement, Midwest Generation and EME assumed responsibility for environmental liabilities associated with the ownership, occupancy, use and operation of the stations, including responsibility for compliance by the stations with environmental laws before their purchase by Midwest Generation. Midwest Generation and EME additionally agreed to indemnify and hold ComEd and its affiliates harmless from claims, fines, penalties, liabilities and expenses arising from third party claims against ComEd resulting from or arising out of the environmental liabilities assumed by Midwest Generation and EME under the terms of the agreement governing the sale. In connection with Exelon's 2001 corporate restructuring, Generation assumed ComEd's rights and obligations with respect to its former generation business, including its rights and obligations under the sale agreement with Midwest Generation and EME.

Under a supplemental agreement reached in 2003, Midwest Generation agreed to reimburse ComEd and Generation for 50% of the specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement.

On December 17, 2012 (Petition Date), EME and certain of its subsidiaries, including Midwest Generation, filed for protection under Chapter 11 of the U.S. Bankruptcy Code.

In 2012, the Bankruptcy Court approved the rejection of an agency agreement related to a coal rail car lease under which Midwest Generation had agreed to reimburse ComEd for all obligations incurred under the coal rail car lease. The rejection left Generation as the party responsible for making all remaining payments under the lease and performing all other obligations thereunder. A settlement was reached in January 2015, to resolve the claims related to the coal rail car lease for approximately \$14 million and Exelon recorded a gain upon receipt of the funds, within Operating and maintenance expense in Exelon and Generation's Consolidated Statement of Operations and Comprehensive Income. No further action is expected related to the rail car lease.

On March 11, 2014, the Bankruptcy Court for the Northern District of Illinois entered its Order Confirming Debtors' Joint Chapter 11 Plan of Reorganization. On April 1, 2014 (Effective Date), NRG Energy purchased EME's portfolio of generation, including Midwest Generation and the Joint Chapter 11 Plan of Reorganization (Plan) became effective. As part of the Plan, the sale agreement, including the environmental indemnity, and the asbestos cost-sharing agreement were rejected.

Generation increased its reserve for asbestos-related bodily injury claims pertaining to Midwest Generation's share of liability as a result of the rejection of the asbestos cost sharing agreement in the bankruptcy.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

proceedings. Exelon and Generation may be entitled to damages associated with the rejection of the agreement and a claim has been filed by Exelon for such damages. These amounts are considered to be contingent gains and would not be recognized until realized.

As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon's 2001 corporate restructuring to assume ComEd's rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors. ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of March 31, 2015. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

***Solid and Hazardous Waste***

***Cotter Corporation.*** The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third-party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon's 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study, and subsequently requested additional analysis sampling and modeling that will be conducted throughout 2015. In light of these additional requests, it is unknown when the U.S. EPA will propose a remedy for public comment, but will likely be sometime in 2016 at the earliest. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote. The current estimated cost of the landfill cover remediation for the site is approximately \$50 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.

On August 8, 2011, Cotter was notified by the DOJ that Cotter is considered a PRP with respect to the government's clean-up costs for contamination attributable to low level radioactive residues at a former storage and reprocessing facility named Latty Avenue near St. Louis, Missouri. The Latty Avenue site is included in ComEd's indemnification responsibilities discussed above as part of the sale of Cotter. The radioactive residues had been generated initially in connection with the processing of uranium ores as part of the U.S. government's Manhattan Project. Cotter purchased the residues in 1969 for initial processing at the Latty Avenue facility for the subsequent extraction of uranium and metals. In 1976, the NRC found that the Latty Avenue site had radiation levels exceeding NRC criteria for decontamination of land areas. Latty Avenue was investigated and remediated by the United States Army Corps of Engineers pursuant to funding under the Formerly Utilized Sites Remedial Action Program. The DOJ has not yet formally advised the PRPs of the amount that it is seeking, but it is believed to be approximately \$90 million. The DOJ and the PRPs agreed to toll the statute of limitations until August 2015 so that settlement discussions could proceed. Based on Generation's preliminary review, it appears probable that Generation has liability to Cotter under the indemnification agreement and has established an appropriate accrual for this liability.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

On February 28, 2012, and April 12, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 15 and 14 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the Exelon defendants' negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon, Generation, and ComEd cannot estimate a range of loss, if any.

**68<sup>th</sup> Street Dump.** In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The PRPs submitted their investigation of the range of clean-up options in the first quarter of 2011. Although the investigation and options provided to the U.S. EPA are still subject to U.S. EPA review and selection of a remedy, the range of estimated clean-up costs to be allocated among all of the PRPs is in the range of \$50 million to \$64 million. On September 30, 2013, U.S. EPA issued the Record of Decision identifying its preferred remedial alternative for the site. The estimated cost for the alternative chosen by U.S. EPA is consistent with the PRPs' estimated range of costs noted above. Based on Generation's preliminary review, it appears probable that Generation has liability and has established an appropriate accrual for its share of the estimated clean-up costs. A wholly owned subsidiary of Generation has agreed to indemnify BGE for most of the costs related to this settlement and clean-up of the site.

**Rossville Ash Site.** The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately \$10 million, which has been fully reserved as of March 31, 2015.

**Sauer Dump.** On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of \$1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRPs signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRPs to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE's reasonably possible loss, if any, cannot be determined.

**Litigation and Regulatory Matters**

Except to the extent noted below, the circumstances set forth in Note 22 of the Exelon 2014 Form 10-K describe, in all material respects, the current status of litigation matters. The following is an update to that discussion.

***Asbestos Personal Injury Claims (Exelon, Generation, PECO and BGE)***

*Exelon and Generation.* Generation maintains a reserve for claims associated with asbestos-related personal injury actions in certain facilities that are currently owned by Generation or were previously owned by ComEd and PECO. The reserve is recorded on an undiscounted basis and excludes the estimated legal costs associated with handling these matters, which could be material.

At March 31, 2015 and December 31, 2014, Generation had reserved approximately \$97 million and \$100 million, respectively, in total for asbestos-related bodily injury claims. As of March 31, 2015, approximately \$20 million of this amount related to 224 open claims presented to Generation, while the remaining \$77 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.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee's disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee's last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court's ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee's last employment-based exposure to asbestos. Currently, Exelon, Generation and PECO are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such no increase to the asbestos-related bodily injury liability has been recorded as of March 31, 2015. Increased claims activity resulting from this ruling could have a material adverse effect on Exelon's, Generation's and PECO's future results of operations and cash flows.

*BGE.* Since 1993, BGE and certain Constellation (now Generation) subsidiaries have been involved in several actions concerning asbestos. The actions are based upon the theory of premises liability, alleging that BGE and Generation knew of and exposed individuals to an asbestos hazard. In addition to BGE and Generation, numerous other parties are defendants in these cases.

Approximately 467 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation's financial results.



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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Discovery begins in these cases after they are placed on the trial docket. At present, only two of the pending cases are set for trial. Given the limited discovery in these cases, BGE and Generation do not know the specific facts that are necessary to provide an estimate of the reasonably possible loss relating to these claims; as such, no accrual has been made and a range of loss is not estimable. The specific facts not known include:

the identity of the facilities at which the plaintiffs allegedly worked as contractors;

the names of the plaintiffs' employers;

the dates on which and the places where the exposure allegedly occurred; and

the facts and circumstances relating to the alleged exposure.

Insurance and hold harmless agreements from contractors who employed the plaintiffs may cover a portion of any awards in the actions.

***Continuous Power Interruption (ComEd)***

Section 16-125 of the Illinois Public Utilities Act provides that in the event an electric utility, such as ComEd, experiences a continuous power interruption of four hours or more that affects (in ComEd's case) more than 30,000 customers, the utility may be liable for actual damages suffered by customers as a result of the interruption and may be responsible for reimbursement of local governmental emergency and contingency expenses incurred in connection with the interruption. Recovery of consequential damages is barred. The affected utility may seek from the ICC a waiver of these liabilities when the utility can show that the cause of the interruption was unpreventable damage due to weather events or conditions, customer tampering, or certain other causes enumerated in the law.

On August 18, 2011, ComEd sought from the ICC a determination that ComEd is not liable for damage compensation to customers in connection with the July 11, 2011 storm system that produced multiple power interruptions that in the aggregate affected more than 900,000 customers in ComEd's service territory, as well as for five other storm systems that affected ComEd's customers during June and July 2011 (Summer 2011 Storm Docket). In addition, on September 29, 2011, ComEd sought from the ICC a determination that it was not liable for damage compensation related to the February 1, 2011 blizzard (February 2011 Blizzard Docket).

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. The ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and therefore no waiver should apply. As required by the ICC's Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. On July 31, 2014, the Illinois Appellate Court reaffirmed the ICC's decision in ComEd's appeal of the Summer 2011 Storm Docket and dismissed ComEd's appeal of the February 2011 Blizzard Docket. The Illinois Supreme Court denied ComEd's request to hear the matter. The ICC's order is now final and claims from impacted customers and municipalities are now eligible for review and reimbursement. ComEd is processing claims received to date.

In the second quarter of 2013, ComEd established a liability, which is not material, for potential reimbursements for actual damages incurred by the 34,559 customers covered by the ICC's June 5, 2013 Order. The liability recorded represents the low end of a range of potential losses given that no amount within the range represents a better estimate. ComEd's ultimate liability will be based on actual claims eligible for reimbursement. Although reimbursements for actual damages will differ from the estimated accrual recorded, at this time ComEd does not expect the difference to be material to ComEd's results of operations or cash flows.



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

ComEd has not recorded an accrual for reimbursement of local governmental emergency and contingency expenses as a range of loss, if any, cannot be reasonably estimated at this time, but may be material to ComEd's results of operations and cash flows.

***Telephone Consumer Protection Act Lawsuit (ComEd)***

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act (TCPA) by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys' fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from \$500 to \$1,500 per text. In February 2014, ComEd filed a motion to dismiss this class action complaint, which was denied in June 2014. On February 19, 2015, ComEd and the plaintiff agreed in principle to settle the suit for \$5 million, which ComEd has recorded as a liability as of March 31, 2015. The parties are in process of obtaining the approval of the court and the class of customers represented in the suit. As ComEd is unable to predict the ultimate outcome of this proceeding, actual damages may differ from the estimated amount recorded, which may be material to ComEd's results of operations, cash flows, and financial position.

***Baltimore City Franchise Taxes (BGE)***

The City of Baltimore claims that BGE has maintained electric facilities in the City's public right-of-ways for over one hundred years without the proper franchise rights from the City. BGE has reviewed the City's claim and believes that it lacks merit. BGE has not recorded an accrual for payment of franchise fees for past periods as a range of loss, if any, cannot be reasonably estimated at this time. Franchise fees assessed in future periods may be material to BGE's results of operations and cash flows.

***General (Exelon, Generation, ComEd, PECO and BGE)***

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.

***Income Taxes (Exelon, Generation, ComEd, PECO and BGE)***

See Note 10 - Income Taxes for information regarding the Registrants' income tax refund claims and certain tax positions, including the 1999 sale of fossil generating assets.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**18. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)****Supplemental Statement of Operations Information**

The following tables provide additional information about the Registrants' Consolidated Statements of Operations and Comprehensive Income for the three months ended March 31, 2015 and 2014:

Three Months Ended March 31, 2015	Exelon	Generation	ComEd	PECO	BGE
<b>Other, Net</b>					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds <sup>(a)</sup>					
Regulatory agreement units	\$ 71	\$ 71	\$	\$	\$
Non-regulatory agreement units	29	29			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	48	48			
Non-regulatory agreement units	40	40			
Net unrealized gains on pledged assets					
Zion Station decommissioning	10	10			
Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>	(106)	(106)			
Total decommissioning-related activities	92	92			
Investment income (expense)	1	1			1 <sup>(c)</sup>
Long-term lease income	4				
Interest income related to uncertain income tax positions		1			
AFUDC Equity	5			2	3
Terminated interest rate swaps <sup>(d)</sup>	(23)	3			
Other	1	(3)	3		
Other, net	\$ 80	\$ 94	\$ 3	\$ 2	\$ 4

Three Months Ended March 31, 2014	Exelon	Generation	ComEd	PECO	BGE
<b>Other, Net</b>					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds <sup>(a)</sup>					
Regulatory agreement units	\$ 43	\$ 43	\$	\$	\$
Non-regulatory agreement units	25	25			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	61	61			
Non-regulatory agreement units	13	13			
Net unrealized losses on pledged assets					
Zion Station decommissioning	10	10			
Regulatory offset to decommissioning trust fund-related activities <sup>(b)</sup>	(94)	(94)			
Total decommissioning-related activities	58	58			

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Investment income (expense)	1	1			2 <sup>(c)</sup>
Long-term lease income	6				
Interest income related to uncertain income tax positions	10	14			
AFUDC Equity	6		3	1	3
Other	17	12	2	1	(1)
Other, net	\$ 98	\$ 85	\$ 5	\$ 2	\$ 4

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

- (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 15 Asset Retirement Obligations of the Exelon 2014 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
- (c) Relates to the cash return on BGE's rate stabilization deferral. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information regarding the rate stabilization deferral.
- (d) In January 2015, in connection with Generation's \$750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, \$26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon's Consolidated Statement of Operations and Comprehensive Income.

**Supplemental Cash Flow Information**

The following tables provide additional information regarding the Registrants' Consolidated Statements of Cash Flows for the three months ended March 31, 2015 and 2014:

Three Months Ended March 31, 2015	Exelon	Generation	ComEd	PECO	BGE
<b>Depreciation, amortization, accretion and depletion</b>					
Property, plant and equipment	\$ 540	\$ 242	\$ 154	\$ 58	\$ 71
Regulatory assets	58		21	4	35
Amortization of intangible assets, net	12	12			
Amortization of energy contract assets and liabilities <sup>(a)</sup>	(31)	(32)			
Nuclear fuel <sup>(b)</sup>	272	272			
ARO accretion <sup>(c)</sup>	97	97			
Total depreciation, amortization, accretion and depletion	\$ 948	\$ 591	\$ 175	\$ 62	\$ 106

Three Months Ended March 31, 2014	Exelon	Generation	ComEd	PECO	BGE
<b>Depreciation, amortization, accretion and depletion</b>					
Property, plant and equipment	\$ 481	\$ 200	\$ 143	\$ 56	\$ 70
Regulatory assets	72		30	2	38
Amortization of intangible assets, net	11	11			
Amortization of energy contract assets and liabilities <sup>(a)</sup>	42	44			
Nuclear fuel <sup>(b)</sup>	234	234			
ARO accretion <sup>(c)</sup>	68	68			
Total depreciation, amortization, accretion and depletion	\$ 908	\$ 557	\$ 173	\$ 58	\$ 108

- (a) Included in Operating revenues or Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.
- (b) Included in Purchased power and fuel expense on the Registrants' Consolidated Statements of Operations and Comprehensive Income.

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(c) Included in Operating and maintenance expense on the Registrants Consolidated Statements of Operations and Comprehensive Income.

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

Three Months Ended March 31, 2015	Exelon	Generation	ComEd	PECO	BGE
<b>Other non-cash operating activities:</b>					
Pension and non-pension postretirement benefit costs	\$ 159	\$ 67	\$ 52	\$ 10	\$ 16
Provision for uncollectible accounts	84	4	22	33	25
Stock-based compensation costs	39				
Other decommissioning-related activity <sup>(a)</sup>	(44)	(44)			
Energy-related options <sup>(b)</sup>	9	9			
Amortization of regulatory asset related to debt costs	3		2	1	
Amortization of rate stabilization deferral	25				25
Amortization of debt fair value adjustment	(9)	(4)			
Discrete impacts of EIMA <sup>(c)</sup>	46		46		
Amortization of debt costs	18	4	1	1	1
Lower of cost or market inventory adjustment	10	10			
Other	4	(1)	3	(1)	(3)
Total other non-cash operating activities	\$ 344	\$ 45	\$ 126	\$ 44	\$ 64
<b>Changes in other assets and liabilities:</b>					
Under/over-recovered energy and transmission costs	\$ 65	\$	\$	\$ 26	\$ 39
Other regulatory assets and liabilities	92		2	(5)	25
Cash deposits <sup>(d)</sup>	226	226			
Other current assets	(155)	(100)	(1)	(95) <sup>(e)</sup>	30
Other noncurrent assets and liabilities	(113)	(41)	(10)	2	(1)
Total changes in other assets and liabilities	\$ 115	\$ 85	\$ (9)	\$ (72)	\$ 93
<b>Non-cash investing and financing activities:</b>					
Indemnification of like-kind exchange position <sup>(f)</sup>			2		
Total non-cash investing and financing activities:	\$	\$	\$ 2	\$	\$



**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Three Months Ended March 31, 2014	Exelon	Generation	ComEd	PECO	BGE
<b>Other non-cash operating activities:</b>					
Pension and non-pension postretirement benefit costs	\$ 173	\$ 75	\$ 56	\$ 12	\$ 16
Equity method investments	19	19			
Provision for uncollectible accounts	35	1	(11)	35	11
Stock-based compensation costs	46				
Other decommissioning-related activity <sup>(a)</sup>	(35)	(35)			
Energy-related options <sup>(b)</sup>	31	31			
Amortization of regulatory asset related to debt costs	3		2	1	
Amortization of rate stabilization deferral	20				20
Amortization of debt fair value adjustment	(12)	(5)			
Discrete impacts from EIMA <sup>(c)</sup>	(4)		(4)		
Amortization of debt costs	5	3	(5)	1	
Increase in inventory reserve	2	2			
Other	(7)	(2)	(2)		(4)
<b>Total other non-cash operating activities</b>	<b>\$ 276</b>	<b>\$ 89</b>	<b>\$ 36</b>	<b>\$ 49</b>	<b>\$ 43</b>
<b>Changes in other assets and liabilities:</b>					
Under/over-recovered energy and transmission costs	\$ (15)	\$	\$ 4	\$ (17)	\$ 23
Other regulatory assets and liabilities	(4)		(10)	(3)	6
Other current assets	(209)	(80)	(29)	(105) <sup>(e)</sup>	18
Other noncurrent assets and liabilities	(50)	(23)	11	(2)	(3)
<b>Total changes in other assets and liabilities</b>	<b>\$ (278)</b>	<b>\$ (103)</b>	<b>\$ (24)</b>	<b>\$ (127)</b>	<b>\$ 44</b>
<b>Non-cash investing and financing activities:</b>					
Indemnification of like-kind exchange position <sup>(f)</sup>			2		
<b>Total non-cash investing and financing activities</b>	<b>\$</b>	<b>\$</b>	<b>\$ 2</b>	<b>\$</b>	<b>\$</b>

(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 15 Asset Retirement Obligations of the Exelon 2014 Form 10-K for additional information regarding the accounting for nuclear decommissioning.

(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.

(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 Regulatory Matters for more information.

(d) Relates primarily to cash deposits recalled from ISOs/RTOs and replaced with letters of credit.

(e) Relates primarily to prepaid utility taxes.

(f) See Note 10 Income Taxes for discussion of the like-kind exchange tax position.

*DOE Smart Grid Investment Grant (Exelon and PECO).* For the three months ended March 31, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of \$2 million and reimbursements of \$2 million related to PECO's DOE SGIG programs. For the three months ended March 31, 2015 PECO had no capital expenditures or reimbursements, as the DOE SGIG program was completed during 2014. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information regarding the DOE SGIG.



**Table of Contents****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 as of March 31, 2015 and December 31, 2014.

March 31, 2015	Exelon	Generation	ComEd	PECO	BGE
<b>Property, plant and equipment:</b>					
Accumulated depreciation and amortization	\$ 15,207 <sup>(a)</sup>	\$ 7,905 <sup>(a)</sup>	\$ 3,247	\$ 2,989	\$ 2,905
<b>Accounts receivable:</b>					
Allowance for uncollectible accounts	\$ 365	\$ 61	\$ 100	\$ 127	\$ 84
December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
<b>Property, plant and equipment:</b>					
Accumulated depreciation and amortization	\$ 14,742 <sup>(b)</sup>	\$ 7,612 <sup>(b)</sup>	\$ 3,432	\$ 2,917	\$ 2,868
<b>Accounts receivable:</b>					
Allowance for uncollectible accounts	\$ 311	\$ 60	\$ 84	\$ 100	\$ 67

(a) Includes accumulated amortization of nuclear fuel in the reactor core of \$2,772 million.

(b) Includes accumulated amortization of nuclear fuel in the reactor core of \$2,673 million.

**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 \$14 million and \$15 million as of March 31, 2015 and December 31, 2014, 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 of the Exelon 2014 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at March 31, 2015 of \$14 million consists of \$1 million, \$4 million and \$9 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2014 of \$15 million consists of \$1 million, \$3 million and \$11 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 March 31, 2015 and December 31, 2014 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 of the Exelon 2014 Form 10-K.

**19. Segment Information (Exelon, Generation, ComEd, PECO and BGE)**

Operating segments for each of the Registrants are determined based on information used by the chief operating decision maker(s) (CODM) in deciding how to evaluate performance and allocate resources at each of the Registrants.

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation's six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions not considered individually significant and referred to collectively as "Other Power Regions"; which includes activities in the South, West and Canada. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon's CODM evaluates the performance of and allocates resources to ComEd, PECO and BGE based on net income and return on equity.

The CODMs for ComEd, PECO, and BGE evaluate performance and allocate resources for their respective companies based on net income and return on equity for ComEd, PECO, and BGE each as single integrated businesses.

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

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

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

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

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

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

Other Power Regions not considered individually significant:

South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

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

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

The CODMs for Exelon and Generation evaluate the performance of Generation's power marketing activities and allocate resources 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

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)****(Dollars in millions, except per share data, unless otherwise noted)**

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 sales to its affiliates, ComEd, PECO and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. Generation's other business activities, including retail and wholesale gas, investments in gas and oil exploration and production activities, proprietary trading, compressed natural gas fueling stations, energy efficiency and cogeneration projects, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, indoor quality systems and home improvements, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation's other miscellaneous revenues, unrealized mark-to-market impact of economic hedging activities, and amortization of certain intangible assets relating to commodity contracts recorded at fair value from prior acquisitions are also 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.

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements for the three months ended March 31, 2015 and 2014 is as follows:

	Generation <sup>(a)</sup>	ComEd	PECO	BGE	Other <sup>(b)</sup>	Intersegment Eliminations	Exelon
<b>Total revenues<sup>(c)</sup>:</b>							
2015	\$ 5,840	\$ 1,185	\$ 985	\$ 1,036	\$ 318	\$ (534)	\$ 8,830
2014	4,390	1,134	993	1,054	290	(624)	7,237
<b>Intersegment revenues<sup>(d)</sup>:</b>							
2015	\$ 210	\$ 1	\$	\$ 7	\$ 316	\$ (533)	\$ 1
2014	316	1	1	16	290	(623)	1
<b>Net income (loss):</b>							
2015	\$ 485	\$ 90	\$ 139	\$ 109	\$ (84)	\$ (1)	\$ 738
2014	(185)	98	89	88	4	(1)	93
<b>Total assets:</b>							
March 31, 2015	\$ 45,318	\$ 25,731	\$ 10,169	\$ 8,130	\$ 10,457	\$ (12,414)	\$ 87,391
December 31, 2014	45,348	25,392	9,943	8,078	9,794	(11,741)	86,814

(a) Generation includes the six power marketing reportable segments shown below: Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions. Intersegment revenues for Generation for the three months ended March 31, 2015 include revenue from sales to PECO of \$63 million and sales to BGE of \$138 million in the Mid-Atlantic region, and sales to ComEd of \$9 million in the Midwest. For the three months ended March 31, 2014, intersegment revenues for Generation include revenue from sales to PECO of \$88 million and sales to BGE of \$120 million in the Mid-Atlantic region, and sales to ComEd of \$108 million in the Midwest region.

(b) Other primarily includes Exelon's corporate operations, shared service entities and other financing and investment activities.

(c) For the three months ended March 31, 2015 and 2014, utility taxes of \$27 million and \$24 million, respectively, are included in revenues and expenses for Generation. For the three months ended March 31, 2015 and 2014, utility taxes of \$62 million and \$63 million, respectively, are included in revenues and expenses for ComEd. For the three months ended March 31, 2015 and 2014, utility taxes of \$35 million and \$35 million, respectively, are included in revenues and expenses for PECO. For the three months ended March 31, 2015 and 2014, utility taxes of \$52 million and \$20 million, respectively, are included in revenues and expenses for BGE.

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with the Generation's sale of certain products and services by and between Exelon's segments is not eliminated in consolidation due to the recognition of intersegment profit in accordance with regulatory accounting guidance. For Exelon, these amounts are included in Operating revenues in the Consolidated Statements of Operations and Comprehensive Income.

**Table of Contents****COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

**Generation total revenues:**

	Three Months Ended March 31, 2015			Three Months Ended March 31, 2014		
	Revenues from external customers <sup>(b)</sup>	Intersegment revenues	Total Revenues <sup>(a)</sup>	Revenues from external customers <sup>(b)</sup>	Intersegment revenues	Total Revenues
Mid-Atlantic	\$ 1,517	\$ (4)	\$ 1,513	\$ 1,441	\$ (23)	\$ 1,418
Midwest	1,275	1	1,276	1,258	12	1,270
New England	858	1	859	545	4	549
New York	310		310	190	(3)	187
ERCOT	182	(2)	180	243		243
Other Power Regions <sup>(c)</sup>	212	2	214	334	7	341
<b>Total Revenues for Reportable Segments</b>	<b>4,354</b>	<b>(2)</b>	<b>4,352</b>	<b>4,011</b>	<b>(3)</b>	<b>4,008</b>
Other <sup>(d)</sup>	1,486	2	1,488	379	3	382
<b>Total Generation Consolidated Operating Revenues</b>	<b>\$ 5,840</b>	<b>\$</b>	<b>\$ 5,840</b>	<b>\$ 4,390</b>	<b>\$</b>	<b>\$ 4,390</b>

- (a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's revenues on a fully consolidated basis.
- (b) Includes all wholesale and retail electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
- (c) Other Power Regions include the South, West and Canada, which are not considered individually significant.
- (d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of \$40 million increase to revenues and \$93 million decrease to revenues, for the three months ended March 31, 2015 and 2014, respectively, unrealized mark-to-market gains of \$154 million and losses of \$760 million for the three months ended March 31, 2015 and 2014, respectively, and elimination of intersegment revenues.

**Generation total revenues net of purchased power and fuel expense:**

	Three Months Ended March 31, 2015			Three Months Ended March 31, 2014		
	RNF from external customers <sup>(b)</sup>	Intersegment RNF	Total RNF <sup>(a)</sup>	RNF from external customers <sup>(b)</sup>	Intersegment RNF	Total RNF
Mid-Atlantic	\$ 784	\$ (2)	\$ 782	\$ 784	\$ (89)	\$ 695
Midwest	701	(1)	700	530	26	556
New England	177	(19)	158	154	(18)	136
New York	174	14	188	(29)	8	(21)
ERCOT	88	(33)	55	155	(72)	83
Other Power Regions <sup>(c)</sup>	99	(53)	46	150	(45)	105
<b>Total Revenues net of purchased power and fuel expense for Reportable Segments</b>	<b>2,023</b>	<b>(94)</b>	<b>1,929</b>	<b>1,744</b>	<b>(190)</b>	<b>1,554</b>

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Other <sup>(d)</sup>	384	94	478	(711)	190	(521)
Total Generation Revenues net of purchased power and fuel expense	\$ 2,407	\$	\$ 2,407	\$ 1,033	\$	\$ 1,033

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**COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

- (a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's revenue net of purchased power and fuel expense on a fully consolidated basis.
- (b) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
- (c) Other Power Regions include the South, West and Canada, which are not considered individually significant.
- (d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of \$38 million increase to RNF and \$42 million decrease to RNF for the three months ended March 31, 2015 and 2014, respectively, unrealized mark-to-market gains of \$162 million and losses of \$730 million for the three months ended March 31, 2015 and 2014, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

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**Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations**

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

**Exelon Corporation**

**General**

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

*Generation*, whose integrated business consists of the generation, physical delivery and marketing of power across multiple geographical regions through its customer-facing business, Constellation, which sells electricity and natural gas to both wholesale and retail customers. Generation also sells renewable energy and other energy-related products and services, and engages in natural gas and oil exploration and production activities (Upstream).

As a result of the Constellation merger, Generation owns a 50.01% interest in CENG. During 2014, Generation assumed the operating licenses and corresponding operational control of CENG's nuclear fleet. As a result, Exelon and Generation fully consolidated CENG's financial position and results of operations into their financial statements since April 1, 2014.

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

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

Exelon has nine reportable segments consisting of Generation's six power marketing reportable segments (Mid-Atlantic, Midwest, New England, New York, ERCOT and Other Power Regions in Generation), ComEd, PECO and BGE. See Note 19 Segment Information of the Combined Notes to Consolidated Financial Statements for additional information regarding Exelon's reportable segments.

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

Exelon's consolidated financial information includes the results of its four separate operating subsidiary registrants, Generation, ComEd, PECO and BGE, which, along with Exelon, are collectively referred to as the Registrants. The following combined Management's Discussion and Analysis of Financial Condition and Results of Operations is separately filed by Exelon, Generation, ComEd, PECO and BGE. However, none of the Registrants makes any representation as to information related solely to any of the other Registrants.

**Table of Contents****Executive Overview**

**Financial Results.** The following consolidated financial results reflect the results of Exelon for the three months ended March 31, 2015 compared to the same period in 2014. All amounts presented below are before the impact of income taxes, except as noted.

	Three Months Ended March 31,						2014 Exelon	Favorable (Unfavorable) Variance
	2015	2015	2015	2015	2015	2015		
	Generation <sup>(a)</sup>	ComEd	PECO	BGE	Other	Exelon <sup>(a)</sup>		
<b>Operating revenues</b>	\$ 5,840	\$ 1,185	\$ 985	\$ 1,036	\$ (216)	\$ 8,830	\$ 7,237	\$ 1,593
<b>Purchased power and fuel</b>	3,433	327	438	487	(215)	4,470	4,340	(130)
<b>Revenue net of purchased power and fuel<sup>(b)</sup></b>	2,407	858	547	549	(1)	4,360	2,897	1,463
<b>Other operating expenses</b>								
Operating and maintenance	1,311	378	222	182	(12)	2,081	1,858	(223)
Depreciation and amortization	254	175	62	106	13	610	564	(46)
Taxes other than income	122	75	41	57	9	304	293	(11)
Total other operating expenses	1,687	628	325	345	10	2,995	2,715	(280)
<b>Equity in losses of unconsolidated affiliates</b>							(19)	19
<b>Gain on sales of assets</b>	(1)		1		1	1	5	(4)
<b>Operating income (loss)</b>	719	230	223	204	(10)	1,366	168	1,198
<b>Other income and (deductions)</b>								
Interest expense, net	(102)	(84)	(28)	(25)	(106)	(345)	(227)	(118)
Other, net	94	3	2	4	(23)	80	98	(18)
Total other income and (deductions)	(8)	(81)	(26)	(21)	(129)	(265)	(129)	(136)
<b>Income (loss) before income taxes</b>	711	149	197	183	(139)	1,101	39	1,062
<b>Income taxes</b>	226	59	58	74	(54)	363	(54)	(417)
<b>Net income (loss)</b>	485	90	139	109	(85)	738	93	645
Net income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	42			3		45	3	(42)
<b>Net income (loss) attributable to common shareholders</b>	\$ 443	\$ 90	\$ 139	\$ 106	\$ (85)	\$ 693	\$ 90	\$ 603

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.

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

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* Exelon's net income attributable to common shareholders was \$693 million for the three months ended March 31, 2015 as compared to \$90 million for the three months ended March 31, 2014, and diluted earnings per average common share were \$0.80 for the three months ended March 31, 2015 as compared to \$0.10 for the three months ended March 31, 2014.



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Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by \$1,463 million for the three months ended March 31, 2015 as compared to the same period in 2014. The year-over-year increase in operating revenue net of purchased power and fuel expense was primarily due to the following favorable factors:

Increase of \$404 million at Generation primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015, the inclusion of Integrys' results in 2015, the benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), and a decrease in fuel costs related to the cancellation of DOE spent nuclear fuel disposal fees; partially offset by a reduction in capacity credits, lower margins resulting from the 2014 sales of generating units, lower realized energy prices and the absence of 2014 fuel optimization opportunities in the South;

Increase of \$81 million at Generation related to amortization of contracts recorded at fair value during prior acquisitions;

Increase of \$892 million at Generation due to mark-to-market gains of \$162 million in 2015 from economic hedging activities as compared to \$730 million in mark-to-market losses in 2014;

Increase of \$44 million at ComEd primarily due to increased cost recovery associated with energy efficiency programs and uncollectible accounts expense (both offset in Operating and maintenance expense), and increased distribution revenue, as a result of higher operating and maintenance expense (offset in Operating and maintenance expense) and increased capital investment, partially offset by lower return on common equity due to a decrease in treasury rates;

Increase of \$18 million at PECO primarily due to favorable weather and volume; and

Increase of \$24 million at BGE primarily due to increased distribution revenue as a result of the December 2014 electric and natural gas distribution rate case orders issued by the Maryland PSC.

Operating and maintenance expense increased by \$223 million for the three months ended March 31, 2015 as compared to the same period in 2014 primarily due to the following unfavorable factors:

Increase in Generation's labor, contracting and materials costs of \$141 million primarily due to the inclusion of CENG's results in 2015 and an increase of \$44 million as a result of an increase in the number of planned nuclear refueling outage days in 2015 due to the inclusion of the CENG plants;

Increase in labor, contracting and materials of \$16 million at ComEd related to increased contracting costs related to EIMA and other preventative and corrective maintenance projects and \$13 million at PECO related to increased contracting costs for maintenance and vegetation management;

Increase in Generation's accretion expense and regulatory fees and assessments of \$23 million and \$17 million, respectively, primarily due to the inclusion of CENG's results in 2015;

Increased costs associated with energy efficiency programs and increased uncollectible accounts expense at ComEd of \$39 million; and

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Increased uncollectible accounts expense at BGE of \$14 million.

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

A decrease in pension and non-pension postretirement benefits expense of \$16 million as a result of cost savings from plan design changes for certain OPEB plans in the second quarter of 2014, partially offset by the unfavorable impact of lower assumed pension and OPEB discount rates for 2015, an increase in the life expectancy assumption for plan participants in 2015, and at Generation, the inclusion of CENG s results for the first quarter of 2015;

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A benefit of \$14 million for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy; and

Decreased storm costs at PECO and BGE of \$75 million and \$19 million, respectively.

Depreciation and amortization expense increased by \$46 million primarily as a result of the inclusion of CENG's results in 2015.

Equity in earnings of unconsolidated affiliates decreased by \$19 million primarily due to CENG's operating results being fully consolidated beginning April 1, 2014 and, as a result, are not reflected as equity method earnings in 2015.

Gains on sales of assets decreased by \$4 million due to decreased asset divestiture activity in 2015.

Taxes other than income increased by \$11 million primarily due to the inclusion of CENG's results in 2015.

Interest expense increased by \$118 million primarily as a result of higher outstanding debt at Generation, and financing agreements related to the pending PHI merger at Exelon Corporate.

Other, net decreased by \$18 million primarily as a result of favorable settlements in 2014 of certain income tax positions on Constellation's 2009-2012 tax returns and a loss of \$26 million on the termination of forward-starting interest rate swaps in 2015 at Exelon Corporate, partially offset by the change in realized and unrealized gains and losses on NDT funds at Generation.

Exelon's effective income tax rates for the three months ended March 31, 2015 and 2014 were 33% and (138.5)%, respectively. See Note 10 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information regarding the components of the effective income tax rates.

For further detail regarding the financial results for the three months ended March 31, 2015, 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 three months ended March 31, 2015 were \$615 million, or \$0.71 per diluted share, compared with adjusted (non-GAAP) operating earnings of \$530 million, or \$0.62 per diluted share for the same period in 2014. In addition to net income attributable to common shareholders, 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. 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.

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The following table provides a reconciliation between net income attributable to common shareholders as determined in accordance with GAAP and adjusted (non-GAAP) operating earnings for the three months ended March 31, 2015 as compared to the same period in 2014. The footnotes below the table provide tax expense (benefit) impacts:

(All amounts after tax)	Three Months Ended March 31,			
	2015		2014	
	Earnings per Diluted Share		Earnings per Diluted Share	
<b>Net Income Attributable to Common Shareholders</b>	\$ 693	\$ 0.80	\$ 90	\$ 0.10
Mark-to-Market Impact of Economic Hedging Activities <sup>(a)</sup>	(100)	(0.11)	443	0.52
Unrealized Gains Related to NDT Fund Investments <sup>(b)</sup>	(24)	(0.03)	(8)	(0.01)
Merger and Integration Costs <sup>(c)</sup>	21	0.02	9	0.01
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps <sup>(d)</sup>	48	0.06		
Amortization of Commodity Contract Intangibles <sup>(e)</sup>	(24)	(0.03)	31	0.04
Tax Settlements <sup>(f)</sup>			(35)	(0.04)
Midwest Generation Bankruptcy Recoveries <sup>(g)</sup>	(6)	(0.01)		
CENG Noncontrolling Interest <sup>(h)</sup>	7	0.01		
<b>Adjusted (non-GAAP) Operating Earnings</b>	\$ 615	\$ 0.71	\$ 530	\$ 0.62

- (a) Reflects the impact of (gains) losses for the three months ended March 31, 2015 and March 31, 2014 (net of taxes of \$63 million and \$287 million, respectively), on Generation s economic hedging activities. See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s hedging activities.
- (b) Reflects the impact of unrealized (gains) losses for the three months ended March 31, 2015 and March 31, 2014 (net of taxes of \$26 million and \$18 million, respectively), on Generation s NDT fund investments for Non-Regulatory Agreement Units. See Note 11 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation s NDT fund investments.
- (c) Reflects certain costs incurred for the three months ended March 31, 2015 and March 31, 2014 (net of taxes of \$13 million and \$6 million, respectively), associated with the Constellation merger, pending PHI acquisition, and, at Generation, the CENG integration and Integrys acquisition, including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, merger commitments, and certain pre-acquisition contingencies.
- (d) For 2015, reflects the impact of losses (gains) on forward-starting interest rate swaps at Exelon Corporate related to anticipated financing of the pending PHI acquisition (net of taxes of \$31 million).
- (e) Reflects the non-cash impact for the three months ended March 31, 2015 and March 31, 2014 (net of taxes of \$14 million and \$20 million, respectively), of the amortization of intangible assets, net, related to commodity contracts recorded at fair value at the Constellation merger and the Integrys acquisition.
- (f) For 2014, reflects a benefit related to the favorable settlement of certain income tax positions on Constellation s 2009-2012 tax returns (net of taxes of \$18 million).
- (g) For 2015, reflects a benefit related to the favorable settlement of a long term lease agreement pursuant to the Midwest Generation bankruptcy (net of taxes of \$4 million).
- (h) Represents Generation s non-controlling interest related to CENG exclusion items, primarily related to the impact of unrealized gains and losses on NDT fund investments.

As discussed above, Exelon has incurred costs associated with the Constellation merger, CENG integration, Integrys acquisition and pending PHI acquisition including employee-related expenses (e.g. severance, retirement, relocation and retention bonuses), integration initiatives, and certain pre-acquisition contingencies.



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For the three months ended March 31, 2015 and 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration and Integrys and pending PHI acquisitions as follows:

Merger, Integration and Acquisition Costs:	Pre-tax Expense				
	Three Months Ended March 31, 2015				
	Generation	ComEd	PECO	BGE	Exelon
Financing <sup>(a)</sup>	\$	\$	\$	\$	\$ 89
Transaction <sup>(b)</sup>					6
Employee-Related <sup>(c)</sup>	4				4
Other <sup>(d)</sup>	7	3	1	1	13
<b>Total</b>	<b>\$ 11</b>	<b>\$ 3</b>	<b>\$ 1</b>	<b>\$ 1</b>	<b>\$ 112</b>

Merger and Integration Costs:	Pre-tax Expense				
	Three Months Ended March 31, 2014				
	Generation	ComEd	PECO	BGE	Exelon
Employee-Related <sup>(c)</sup>	\$ 4	\$	\$	\$	\$ 4
Other <sup>(d)</sup>	10				10
<b>Total</b>	<b>\$ 14</b>	<b>\$</b>	<b>\$</b>	<b>\$</b>	<b>\$ 14</b>

(a) Reflects costs incurred at Exelon related to the financing of the PHI merger, including upfront credit facility fees.

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

(c) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

(d) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the three months ended March 31, 2015, also includes professional fees primarily related to integration for the proposed PHI acquisition.

As of March 31, 2015, Exelon projects incurring total PHI acquisition and integration related costs over the next five years of approximately \$635 million, of which approximately \$100 million is expected to be capitalized to property, plant and equipment excluding the direct investment Exelon and PHI have proposed to the PHI utilities respective customers.

Pursuant to the conditions set forth by the MDPSC in its approval of the Exelon and Constellation merger transaction, Exelon committed to provide a package of benefits to BGE customers, and make certain investments in the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of approximately \$1 billion. The direct investment estimate includes \$95 million to \$120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation's competitive energy businesses. On March 20, 2013, Generation signed a 20-year lease agreement that was contingent upon the developer obtaining all required approvals, permits and financing for the construction of a building in Baltimore, Maryland. The operating lease became effective during the second quarter of 2014 when these outstanding contingencies were met by the developer. Construction began late in the second quarter of 2014 and the building is expected to be ready for occupancy a minimum of two years from the start of construction. See Note 17 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

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***Exelon's Strategy and Outlook for the remainder of 2015 and Beyond***

Exelon's value proposition and competitive advantage come from its scope and scale across the energy value chain and its core strengths of operational excellence and financial discipline. Exelon's strategy is to leverage its integrated business model to create value and diversify its business. Exelon's competitive and regulated businesses feature a mix of attributes that, when combined, offer shareholders and customers a unique value proposition:

Generation's competitive businesses provide commodity exposure and a platform to diversify into adjacent markets, while providing residual dividend support.

Exelon's utilities provide a foundation for stable earnings and dividend support, which translates to a stable currency in our stock. Exelon believes its strategy provides a platform for optimal success in an energy industry experiencing fundamental and sweeping change. While enhancing Exelon's core value, it enables it to take advantage of a myriad of opportunities, rather than focusing on any one segment of the energy industry value chain.

Generation's competitive businesses create value for customers by providing innovative solutions and reliable, clean and affordable energy. Generation's electricity generation strategy is to pursue opportunities that provide generation to load matching and that diversify the generation fleet by expanding Generation's regional and technological footprint. Generation leverages its energy generation portfolio to ensure delivery of energy to both wholesale and retail customers under long-term and short-term contracts, and in wholesale power markets. Generation's customer facing activities foster development and delivery of other innovative energy-related products and services for its customers. Generation operates in well-developed energy markets and employs an integrated hedging strategy to manage commodity price volatility. Its generation fleet, including its nuclear plants which consistently operate at high capacity factors, also provide geographic and supply source diversity. These factors help Generation mitigate the current challenging conditions in competitive energy markets.

Exelon's utility strategy is to improve reliability and operations and enhance the customer experience, while ensuring ratemaking mechanisms provide the utilities fair financial returns. The Exelon utilities only invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. The Exelon utilities make these investments prudently and at the lowest reasonable cost to customers. Exelon seeks to leverage its scale and expertise across the utilities platform through enhanced standardization and sharing of best practices to achieve improved operational and financial results. Combined, the utilities plan to invest approximately \$16 billion over the next five years in smart meter technology, transmission projects, gas infrastructure, and electric system improvement projects, providing greater reliability and improved service for our customers and a stable return for the company.

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

Various market, financial, and other factors could affect the Registrants' success in pursuing their strategies. Exelon continues to assess infrastructure, operational, commercial, policy, and legal solutions to these issues. See ITEM 1A. RISK FACTORS of the Exelon 2014 Form 10-K for additional information regarding market and financial factors.

***Proposed Merger with Pepco Holdings, Inc. (Exelon)***

On April 29, 2014, Exelon and PHI signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI's shareholders will receive \$27.25 of cash in exchange for each share of PHI common

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stock. Exelon intends to fund the all-cash transaction using a combination of approximately \$3.5 billion of debt, up to \$1 billion cash from asset sales primarily at Generation, and the remainder through issuance of equity (including mandatory convertible securities). In addition, Exelon entered into a 364-day \$7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing, which has subsequently been reduced to \$3.2 billion as a result of execution of the 2014 equity issuance and the net after-tax cash proceeds from generating asset divestitures during the second half of 2014. See Note 4 Mergers, Acquisitions, and Dispositions, Note 9 Debt and Credit Agreements, and Note 15 Common Stock of the Combined Notes to Consolidated Financial Statements for further information related to these transactions. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased \$144 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI as of March 31, 2015, with additional investments of \$18 million to be made quarterly up to a maximum aggregate investment of \$180 million. As part of the applications for approval of the merger, under pending or final settlements reached to date, as well as other filings, Exelon and PHI have proposed a package to the PHI utilities' respective customers, providing for direct investment in excess of approximately \$300 million with the actual amount and timing of any related payments dependent upon settlement discussions in merger regulatory approval proceedings and the terms of regulatory orders approving the merger.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it has substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22, 2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI have cooperated with the DOJ regarding the proposed merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBP) and the FERC have approved the merger of PHI and Exelon. The Federal Communications Commission has also approved the transfer of certain PHI communications licenses. On February 11, 2015, the NJBP approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBP staff, and the Independent Energy Coalition.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the Delaware Public Service Commission (DPSC) to review the proposed merger. The settlement, which was amended on April 7, 2015 and is subject to the approval of the DPSC, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the PSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environment Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI have proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of \$40 million for DPL customers in Delaware, \$2 million of funding for energy efficiency programs for DPL low income customers, and \$2 million of funding for workforce development.

On March 17, 2015, Exelon and PHI announced that they had reached a settlement agreement with Montgomery and Prince George's Counties in the proceeding before the MDPSC to review the proposed merger. The settlement, which is subject to the approval of the MDPSC, was signed and filed by Exelon, PHI, Montgomery County, Prince George's County, the National Consumer Law Center, National Housing Trust, Maryland Affordable Housing Coalition, the Housing Association of Nonprofit Developers and a consortium of nine recreational trail advocacy organizations led by the Mid-Atlantic Off-Road Enthusiasts. As part of this settlement, Exelon and PHI have proposed a package of benefits to Potomac Electric Power Company (Pepco) and DPL customers and the state of Maryland including the establishment of a customer investment fund of \$94.4 million for utility customers in Maryland. A portion of the customer investment fund, representing

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approximately \$36.8 million, will provide bill credits to Pepco and DPL customers in Maryland, with the remaining \$57.6 million funding energy-efficiency programs, including programs targeted to help low income customers lower their energy bills. Exelon also agreed to establish a Green Sustainability Fund (GSF) of \$50 million to be allocated across the service territories of Pepco, DPL and ACE, with \$19.8 million allocated to Maryland. The GSF will be allocated within each state to state and local green banks and similar sponsoring organizations to make loans to finance public and private investment in renewable energy, microgrids, and other developing energy technologies. Loans made by sponsoring organizations from the GSF must mature within 20 years following the merger closing. At the end of that 20 year period, principal payments received by the sponsoring organizations must be returned to Exelon, but Exelon's recovery of the entire GSF is not assured. In the settlement, Exelon also agreed to provide \$4 million in funding for workforce development in Maryland and made various other commitments, including a commitment to develop 15 MW of commercial solar projects in Maryland. In a related agreement with Prince George's County, Exelon agreed to develop an additional 5 MW of solar generation in Maryland, the output of which will be delivered to Prince George's County under a 30-year PPA at no cost to the county for the first 15 years and at market pricing for the second 15 years. This agreement also requires Prince George's County to purchase substantially all of its requirements for electricity and natural gas from an Exelon affiliate for a period of 15 years at competitive pricing. The County will be free to purchase its requirements for electricity and natural gas from other qualified alternative energy suppliers if and to the extent that competing bidders offer a lower price than that offered by the Exelon affiliate.

On March 10, 2015, Exelon and PHI announced that they had reached a settlement agreement with the Alliance for Solar Choice, a group of solar developers, in the proceeding before the MDPSC. The settlement, which is subject to the approval of the MDPSC, provides for enhancements to the interconnection process for behind-the-meter distributed generation and storage projects.

Exelon has been named in suits filed in the Delaware Chancery Court alleging that individual directors of PHI breached their fiduciary duties by entering into the proposed merger transaction and Exelon aided and abetted the individual directors' breaches. The suits seek to enjoin PHI from completing the merger or seek rescission of the merger if completed. In addition, they also seek unspecified damages and costs. Exelon was also named in a federal court suit making similar claims. In September 2014, the parties reached a proposed settlement that would resolve all claims, which is subject to court approval. Final court approval of the proposed settlement is not anticipated until approximately 90 days after merger close. Exelon does not believe these suits will impact the completion of the transaction, and they are not expected to have a material impact on Exelon's results of operations.

Including 2014 and through March 31, 2015, Exelon has incurred approximately \$289 million of expense associated with the proposed merger, primarily \$69 million related to acquisition and integration costs and \$220 million of costs incurred to finance the transaction.

The Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from \$259 million to \$293 million plus certain expenses. If the Merger Agreement is terminated due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, through the redemption by PHI of the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock, plus certain expenses.

Exelon has listed various potential risks relating to the pending merger with PHI (see ITEM 1A. RISK FACTORS of the Exelon 2014 Form 10-K), including difficulties that may be encountered in satisfying the conditions to completion of the merger and the potential for developments that might have an adverse effect on Exelon and the ability to realize the expected benefits of the merger. Exelon is taking steps to manage these risks and expects that the merger can be completed on a basis favorable to the company's shareholders and customers. Exelon and PHI continue to expect the merger to be completed late in the second or third quarter of 2015. Refer to Note 4 Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

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**Power Markets**

**Price of Fuels.** The use of new technologies to recover natural gas from shale deposits is increasing natural gas supply and reserves, which places downward pressure on natural gas prices and, therefore, on wholesale and retail power prices, which results in a reduction in Exelon's revenues. Forward natural gas prices have declined significantly over the last several years; in part reflecting an increase in supply due to strong natural gas production (due to shale gas development).

**Capacity Market Changes in PJM.** In the wake of the January 2014 Polar Vortex that blanketed much of the Eastern and Midwestern United States, it became clear that while a major outage event was narrowly avoided, resources in PJM were not providing the level of reliability expected by customers. As a result, on December 12, 2014, PJM filed at FERC a proposal to make significant changes to its current capacity market construct, the Reliability Pricing Model (RPM). PJM's proposed changes generally seek to improve resource performance and reliability largely by limiting the excuses for non-performance and by increasing the penalties for performance failures. The proposal permits suppliers to include in capacity market offers additional costs and risk so they can meet these higher performance requirements. While offers are expected to put upward pressure on capacity clearing prices, operational improvements made as a result of PJM's proposal are expected to improve reliability, to reduce energy production costs as a result of more efficient operations and to reduce the need for out of market energy payments to suppliers. Exelon participated actively in PJM's stakeholder process through which PJM developed the proposal and is also actively participating in the FERC proceeding including filing comments. On March 31, 2015, the FERC issued a Deficiency Order seeking further details regarding various aspects of the proposed reforms, but focused on the proposed default offer cap. In response, PJM acquiesced to modifications suggested by the Market Monitor addressing concerns about the default offer cap. FERC could issue a final order any time between April 25, 2015 and June 9, 2015. PJM also sought approval from the FERC to delay the 2018/19 RPM Base Residual Auction that would otherwise be conducted in May, 2015. On April 24, 2015, the FERC issued an order allowing the delay. Thus, PJM is expected to conduct the 2018/19 capacity auction within 30 to 75 days after the issuance of FERC's final order on the proposed capacity market reforms. The specific parameters of that auction could change depending on the FERC determinations in that final order.

**MISO Capacity Market Results.** On April 14, 2015, the Midcontinent Independent System Operator (MISO) released the results of its capacity auction covering the June 2015 through May 2016 delivery year. As a result of the auction, capacity prices for the downstate Illinois zone will increase to \$150/MW per day beginning in June 2015, an increase from the current pricing of \$16.75/MW per day that is in effect from June 2014 to May 2015. However, due to Generation's ratable hedging strategy, the results of the capacity auction are not expected to have a material impact on Exelon and Generation's consolidated results of operations and cash flows.

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

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

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Exelon and others have challenged the constitutionality and other aspects of the New Jersey legislation and the actions taken by the MDPS in state and federal courts. Ultimately, the Exelon parties prevailed in obtaining orders from the U.S. Court of Appeals for the Third Circuit and the U.S. Court of Appeals for the Fourth Circuit effectively undoing the actions taken by the New Jersey legislature and the MDPS, respectively. The matter has been appealed to the U.S. Supreme Court, and while the Court of Appeals decisions are helpful, there remains risk the Supreme Court will overrule the lower Courts.

As required under their contracts, generator developers who were selected in the New Jersey and Maryland programs (including CPV) offered and cleared in PJM's capacity market auctions held in May 2012, 2013, and 2014. In addition, CPV has announced its intention to move forward with construction of its New Jersey and Maryland plants, with or without the challenged state subsidy. Nonetheless to the extent that the state-required customer subsidies are included under their respective contracts, Exelon believes that these projects may have artificially suppressed capacity prices in PJM in these auctions and may continue to do so in future auctions to the detriment of Exelon's market driven position. While the court decisions in New Jersey and Maryland are positive developments, continuation of these state efforts, if successful and unabated by an effective minimum offer price rule (MOPR) for future capacity auctions, could continue to result in artificially depressed wholesale capacity and/or energy prices. Other states could seek to establish programs, which could substantially impact Exelon's market driven position and could have a significant effect on Exelon's financial results of operations, financial position and cash flows. Exelon continues to monitor developments and participate in stakeholder and other processes to ensure that similar state subsidies are not developed. In addition, Exelon remains active in advocating for competitive markets, while opposing policies that require taxpayers and/or consumers to subsidize or give preferential treatment to specific generation providers or technologies, or that would threaten the reliability and value of the integrated electricity grid.

**Energy Demand.** Modest economic growth partially offset by energy efficiency initiatives is resulting in positive growth for electricity for PECO and BGE, and a decrease in projected load for electricity for ComEd. PECO, BGE and ComEd are projecting load volumes to increase (decrease) by 0.9%, 0.1% and (0.1)% respectively, in 2015 compared to 2014.

**Retail Competition.** Generation's retail operations compete for customers in a competitive environment, which affect the margins that Generation can earn and the volumes that it is able to serve. The market experienced high price volatility in the first quarter of 2014 which contributed to bankruptcies and consolidations within the industry during the year. However, forward natural gas and power prices are expected to remain low and thus we expect retail competitors to stay aggressive in their pursuit of market share, and that wholesale generators (including Generation) will continue to use their retail operations to hedge generation output.

**Strategic Policy Alignment**

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

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

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Exelon's board of directors declared the first quarter 2015 dividend of \$0.31 per share on Exelon's common stock. The first quarter dividend was paid on March 10, 2015, to shareholders of record on February 13, 2015.

Exelon's board of directors declared the second quarter 2015 dividend of \$0.31 per share on Exelon's common stock. The second quarter dividend is payable on June 10, 2015 to shareholders of record on May 15, 2015. All future quarterly dividends require approval by Exelon's board of directors.

### **Hedging Strategy**

Exelon's policy to hedge commodity risk on a ratable basis over three-year periods is intended to reduce the financial impact of market price volatility. Generation is exposed to commodity price risk associated with the unhedged portion of its electricity portfolio. Generation enters into non-derivative and derivative contracts, including financially-settled swaps, futures contracts and swap options, and physical options and physical forward contracts, all with credit-approved counterparties, to hedge this anticipated exposure. Generation has hedges in place that significantly mitigate this risk for 2015 and 2016. However, Generation is exposed to relatively greater commodity price risk in the subsequent years with respect to which a larger portion of its electricity portfolio is currently unhedged. As of March 31, 2015, the percentage of expected generation hedged for the major reportable segments is 94%-97%, 67%-70% and 37%-40% for 2015, 2016, and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, such as wholesale and retail sales of power, options and swaps. Generation has been and will continue to be proactive in using hedging strategies to mitigate commodity price risk in subsequent years as well. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for more detail regarding the divestitures.

Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2015 through 2019 are supplied by three producers. In the event of non-performance by these or other suppliers, Generation believes that replacement uranium concentrates can be obtained, although at prices that may be unfavorable when compared to the prices under the current supply agreements. Non-performance by these counterparties could have a material adverse impact on Exelon's and Generation's results of operations, cash flows and financial position.

ComEd, PECO and BGE mitigate commodity price risk through regulatory mechanisms that allow them to recover procurement costs from retail customers.

### **Growth Opportunities**

With an emphasis on innovation and entrepreneurship, Exelon is currently pursuing growth in both the utility and competitive energy businesses. Identifying and capitalizing on emerging trends and technologies, Exelon plans to invest in new innovative technologies to compete with a new breed of energy players, leverage new technologies to create new or expand existing businesses, and improve productivity and efficiencies within our existing businesses. Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas.

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### **Competitive Energy Businesses**

Generation continues to pursue growth in its existing businesses and markets and further diversification across the competitive energy value chain.

#### *Leveraging its competencies,*

Generation's 2014 acquisition of Integrys allows Generation to expand its retail footprint further in an industry sector that continues to mature and consolidate and provides hedging and diversification benefits to its existing portfolio.

Generation continues to pursue investment opportunities in renewables, in its nuclear uprate program and in the development of natural gas generation plants that is supported by the trend of increasing natural gas supply.

#### *Investing in business diversification to position the company for the future,*

Generation has launched a business in competitive distributed generation that capitalizes on the push toward a decentralized system.

Generation is also making investments across the natural gas value chain throughout North America, focusing initially on expansion of the existing Upstream and wholesale gas businesses, as well as entry into liquefied natural gas.

### **Regulated Energy Businesses**

The proposed acquisition of PHI provides an opportunity to accelerate Exelon's regulated growth and provide stable cash flows, earnings accretion, and dividend stability. Additionally, ComEd, PECO and BGE anticipate making significant future investments in infrastructure modernization, including smart meter and smart grid initiatives, storm hardening, and advanced reliability technologies. ComEd also plans to invest approximately \$280 million to construct the Grand Prairie Gateway Transmission Line in Illinois alleviating identified congestion and enhancing reliability. ComEd, PECO and BGE invest in rate base where it provides a net benefit to customers and the community by increasing reliability and the service experience or otherwise meeting customer needs. These investments are made prudently and at the lowest reasonable cost to customers.

See Note 5 – Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on the Smart Meter and Smart Grid Initiatives.

### **Liquidity**

Each of the Registrants annually evaluates its financing plan, dividend practices and credit line sizing, focusing on maintaining its investment grade ratings while meeting its cash needs to fund capital requirements, retire debt, pay dividends, fund pension and OPEB obligations and invest in new and existing ventures. A broad spectrum of financing alternatives beyond the core financing options can be used to meet its needs and fund growth including monetizing assets in the portfolio via project financing, asset sales, and the use of other financing structures (e.g., joint ventures, minority partners, etc.). The Registrants expect cash flows to be sufficient to meet operating expenses, financing costs and capital expenditure requirements.

Exelon, Generation, ComEd, PECO and BGE have unsecured syndicated revolving credit facilities with aggregate bank commitments of \$0.5 billion, \$5.3 billion, \$1.0 billion, \$0.6 billion and \$0.6 billion, respectively. Generation also has bilateral credit facilities with aggregate maximum availability of \$0.5 billion. See Liquidity and Capital Resources – Credit Matters – Exelon Credit Facilities below.



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***Exposure to Worldwide Financial Markets.*** Exelon has exposure to worldwide financial markets including European banks. Disruptions in the European markets could reduce or restrict the Registrants' ability to

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secure sufficient liquidity or secure liquidity at reasonable terms. As of March 31, 2015, approximately 29%, or \$2.5 billion, of the Registrants aggregate total commitments were with European banks, excluding the unsecured bridge facility to provide financing for the proposed PHI acquisition. The credit facilities include \$8.5 billion in aggregate total commitments of which \$6.5 billion was available as of March 31, 2015, due to outstanding letters of credit and commercial paper. There were no borrowings under the Registrants credit facilities as of March 31, 2015. See Note 9 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

### **Tax Matters**

See Note 10 Income Taxes of the Combined Notes to Consolidated Financial Statements for additional information.

### ***Environmental Legislative and Regulatory Developments.***

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

*Air Quality.* In recent years, the U.S. EPA has been implementing a series of increasingly stringent regulations under the Clean Air Act relating to NAAQS for conventional air pollutants (e.g., NO<sub>x</sub>, SO<sub>2</sub> and particulate matter) as well as stricter technology requirements to control HAPs (e.g., acid gases, mercury and other heavy metals) from electric generation units. The U.S. EPA continues to review and update its NAAQS with a tightened particulate matter NAAQS issued in December 2012 and a tightened ozone NAAQS, to be finalized in late 2015, proposed for public comment in December 2014. These recently finalized or proposed updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations. There continues to be opposition among fossil-fuel generation owners to the potential stringency and timing of these air regulations.

In July 2011, the U.S. EPA published CSAPR and in June 2012, it issued final technical corrections. CSAPR requires 28 upwind states in the eastern half of the United States to significantly improve air quality by reducing power plant emissions that cross state lines and contribute to ground-level ozone and fine particle pollution in downwind states. On August 21, 2012, a three-judge panel of the D.C. Circuit Court held that the U.S. EPA had exceeded its authority in certain material aspects with respect to CSAPR and vacated the rule and remanded it to the U.S. EPA for further rulemaking consistent with its decision. The Court also ordered that CAIR remain in effect pending finalization of CSAPR on remand. On April 29, 2014, the U.S. Supreme Court reversed the D.C. Circuit Court decision and upheld CSAPR, and remanded the case to the D.C. Circuit Court to resolve the remaining implementation issues. On November 21, 2014, the U.S. EPA issued an Interim Final Rule in which the Agency announced that it was tolling the effective dates for the CSAPR. The first phase of the CSAPR program started on January 1, 2015, with the second phase starting January 1, 2017. Also released on November 21, 2014, was a Notice of Data Availability under which the Agency proposed CSAPR allowance allocations to generating units for the first five years of the program, 2015- 2020; these were identical to those previously identified in prior final rules related to the CSAPR. Oral argument related to the residual CSAPR challenges, not addressed by the U.S. Supreme Court, occurred on February 25, 2015 before the D.C. Circuit Court.

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On December 16, 2011, the U.S. EPA signed a final rule to reduce emissions of toxic air pollutants from power plants and signed revisions to the NSPS for electric generating units. The final rule, known as MATS, requires coal-fired electric generation plants to achieve high removal rates of mercury, acid gases and other metals. To achieve these standards, coal units with no pollution control equipment installed (uncontrolled coal units) will have to make capital investments and incur higher operating expenses. It is expected that owners of smaller, older, uncontrolled coal units will retire the units rather than make these investments. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. The MATS rule requires generating stations to meet the new standards three years after the rule takes effect, April 16, 2015, with specific guidelines for an additional one or two years in limited cases. Numerous entities challenged MATS in the D.C. Circuit Court, and Exelon intervened in support of the rule. On April 15, 2014, the D.C. Circuit Court issued an opinion upholding MATS in its entirety.

In November 2014, the U.S. Supreme Court granted a petition for review of the MATS Rule filed by 20 states and a coalition of coal-fired electric generators. The U.S. Supreme Court is reviewing a single, yet critical, aspect of the MATS Rule-whether the U.S. EPA properly considered compliance costs (e.g., pollution control capital expenditures and on-going operations and maintenance expense) in determining whether it is appropriate to regulate hazardous air pollutants emitted by electric utilities. If the Court finds that the U.S. EPA acted unreasonably, then implementation of the rule would be delayed until the U.S. EPA corrects any deficiencies. Oral argument was held on March 25, 2015 and it is likely that the U.S. Supreme Court will issue a decision sometime in 2015. Exelon has been participating in the case as an intervenor in support of the rule.

The U.S. EPA continued its regular, periodic review of the NAAQS standards. On November 25, 2014, the Agency proposed, for public comment, the establishment of a revised primary ozone standard in the range of 65-70 parts per billion (ppb) 8-hour average, a reduction from the 2008 ozone standard level of 75 ppb 8-hour average standard. The Agency is also requesting public comment on levels as low as 60 ppb 8-hour average. In its proposal, the Agency is also proposing to extend the ozone season monitoring period, starting in 2017, on a state-by-state basis from its current May-September five-month period to include months before, and after, the traditional ozone season, depending on air quality monitoring data. Most CSAPR states are proposed to be subjected to a March to October ozone season. In its proposed rule, the Agency also elected to set the secondary standard at the same level and form as the primary standard. The Agency is expected to issue its final ozone NAAQS revision in October 2015. In December 2012, the U.S. EPA issued its final revisions to the Agency's particulate matter (PM) NAAQS. In its final rule, the U.S. EPA lowered the annual PM2.5 standard, but declined to issue a new secondary NAAQS to improve urban visibility. The U.S. EPA indicated in its final rule that by 2020 it expects most areas of the country will be in attainment of the new PM2.5 NAAQS based on currently expected regulations, such as the MATS regulation.

In addition to these NAAQS, the U.S. EPA also finalized nonattainment designations for certain areas in the United States for the 2010 one-hour SO2 standard on August 5, 2013, and indicated that additional nonattainment areas will be designated in a future rulemaking. U.S. EPA required states to submit state implementation plans (SIPs) for nonattainment areas by March 25, 2015. With regard to Texas and Maryland, no nonattainment areas were identified in EPA's final designation rule. With regard to Illinois and Pennsylvania, several counties, or portions of counties, in each state were identified as nonattainment. Since the 2010 one-hour SO2 standard was finalized, EPA has issued a series of guidance documents, and proposed a Data Requirement Rule that will be finalized in the summer of 2015 related to requirements for states related to the application of air quality monitoring and modeling in state implementation plans. Nonattainment county compliance with the one-hour SO2 standard is required by March 25, 2018. While significant SO2 reductions will occur as a result of MATS compliance in 2015, Exelon is unable to predict the requirements of pending states' SIPs to further reduce SO2 emissions in support of attainment of the one hour SO2 standard.

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The cumulative impact of these air regulations could be to require fossil fuel-fired power plant operators to expend significant capital to install pollution control technologies, including wet flue gas desulfurization technology for SO<sub>2</sub> and acid gases, and selective catalytic reduction technology for NO<sub>x</sub>.

As of March 31, 2015, Exelon had a \$365 million net investment in coal-fired plants in Georgia subject to long-term leases extending through 2028 and 2030. 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, after the impairments recorded in the second quarter of 2013 and 2014, final applications of the CSAPR and MATS regulations could negatively impact the end-of-lease term values of these assets, which could result in a future impairment loss that could be material.

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

In the absence of Federal legislation, the U.S. EPA is also moving forward with the regulation of GHG emissions under the Clean Air Act. On June 25, 2013, President Obama announced The President's Climate Action Plan, a summary of executive branch actions intended to: reduce carbon emissions; prepare the United States for the impacts of climate change; and lead international efforts to combat global climate change and prepare for its impacts. Concurrent with the announcement of the Administration's plan, the President also issued a Memorandum for the Administrator of the Environmental Protection Agency that focused on power generation sector carbon reductions under the Section 111 New Source Performance Standards (NSPS) section of the federal Clean Air Act. The memorandum directs the U.S. EPA Administrator to issue two sets of proposed rulemakings with regard to power plant carbon emissions under Section 111 of the Clean Air Act.

The U.S. EPA proposed a Section 111(b) regulation for new units in September 2013 that may result in material costs of compliance for CO<sub>2</sub> emissions for new fossil-fuel electric generating units, particularly coal-fired units. The Climate Action Plan also required the U.S. EPA to propose by June 2014 GHG emission regulations for existing stationary sources under Section 111(d) of the Clean Air Act, and to issue final regulations by June 2015. The proposed rule was published in the Federal Register on June 16, 2014. The proposed rule establishes emission reduction targets for each state and provides flexibility for each state to determine how to achieve its required reductions, including heat rate improvements at coal-fired power plants, fuel switching from coal to gas, renewable generation and new nuclear facilities, demand side energy efficiency, and the use of market-based instruments. The U.S. EPA anticipates that the final rule will be issued in summer 2015. While the nature and impact of the final regulations is not yet known, to the extent that the rule results in emission reductions from fossil fuel fired plants, imposing some form of direct or indirect price of carbon in competitive electricity markets, Exelon's overall low-carbon generation portfolio results would benefit.

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

*Water Quality.* Section 316(b) of the Clean Water Act requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts, and is implemented through state-level NPDES permit programs. All of Generation's and CENG's power generation facilities with cooling water systems are subject to the regulations. Facilities without closed-cycle recirculating systems (e.g., cooling towers) are potentially most affected by changes to the existing regulations. For Generation, those facilities are Clinton, Dresden, Eddystone, Fairless Hills, Gould Street, Handley, Mountain

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Creek, Mystic 7, Oyster Creek, Peach Bottom, Quad Cities, Riverside, Salem and Schuylkill. For CENG, those facilities are Calvert Cliffs, Nine Mile Point Unit 1 and R.E. Ginna. On October 14, 2014, the U.S. EPA's final Section 316(b) rule became effective. The rule requires that a series of studies and analyses be performed at each facility to determine the best technology available, followed by an implementation period. The timing of the various requirements for each facility is related to the status of its current NPDES permit and the subsequent renewal period. There is no fixed compliance schedule, as this is left to the discretion of the state permitting director.

Until the compliance requirements are determined by the applicable state permitting director on a site-specific basis for each plant, the impact of compliance with the final rule is unknown. Should a state permitting director determine that a facility is required to install cooling towers to comply with the rule, that facility's economic viability would be called into question. However, the likely impact of the rule has been significantly decreased since the final rule does not mandate cooling towers as a national standard, and the state permitting director is required to apply a cost-benefit test and take into consideration site-specific factors.

*Hazardous and Solid Waste.* On December 19, 2014, the U.S. EPA issued the first federal regulation for the disposal of coal combustion residuals (CCR) from power plants, including the classification of CCR as non-hazardous waste under RCRA. The EPA ruling was published in the Federal Register on April 17, 2015, and becomes effective 180 days after publication. Under the regulation, CCR will continue to be regulated by most states subject to coordination with the federal regulations. Generation has previously recorded reserves consistent with state regulation for its owned coal ash sites, and as such, the regulation is not expected to impact Exelon's and Generation's financial results. Generation does not have sufficient information to reasonably assess the potential likelihood or magnitude of any remediation requirements that may be asserted under the new federal regulations for coal ash disposal sites formerly owned by Generation. For these reasons, Generation is unable to predict whether and to what extent it may ultimately be held responsible for remediation and other costs relating to formerly owned coal ash disposal sites under the new regulations, and as a result no new liability has been recorded as of March 31, 2015.

See Note 17 – Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further detail related to environmental matters.

**Other Regulatory and Legislative Actions**

*NRC Task Force Insights from the Fukushima Daiichi Accident (Exelon and Generation).* In July 2011, an NRC Task Force formed in the aftermath of the March 11, 2011, 9.0 magnitude earthquake and ensuing tsunami, that seriously damaged the nuclear units at the Fukushima Daiichi Nuclear Power Station, issued a report of its review of the accident, including tiered recommendations for future regulatory action by the NRC to be taken in the near and longer term. The Task Force's report concluded that nuclear reactors in the United States are operating safely and do not present an imminent risk to public health and safety. The NRC and its staff have issued orders and implementation guidance for commercial reactor licensees operating in the United States. The NRC and its staff are continuing to evaluate additional requirements. Generation has assessed the impacts of the Tier 1 orders and information requests and will continue monitoring the additional recommendations under review by the NRC staff, both from an operational and a financial impact standpoint. A comprehensive review of the NRC Tier 1 orders and information requests, as well as preliminary engineering assumptions and analysis, indicate that the financial impact of compliance for Generation, net of expected co-owner reimbursements, for the period from 2015 through 2019 is expected to be between approximately \$325 million and \$350 million of capital (including approximately \$75 million for the CENG plants) and \$75 million of operating expense (including approximately \$25 million for the CENG plants). As Generation completes the design and installation planning for its actions, Generation will update these estimates. Further, Generation estimates incremental costs of \$15 to \$20 million per unit at thirteen Mark I and II units (including two CENG units) for the installation of filters on vents, if ultimately required by the NRC. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3

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recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Executive Overview of the Exelon 2014 Form 10-K, for additional information.

***Financial Reform Legislation (Exelon, Generation, ComEd, PECO and BGE).*** The Dodd-Frank Wall Street Reform and Consumer Protection Act (the Act) was enacted in July 2010. The part of the Act that applies to Exelon is Title VII, which is known as the Dodd-Frank Wall Street Transparency and Accountability Act (Dodd-Frank). Dodd-Frank requires the creation of a new regulatory regime for over-the-counter swaps (Swaps), including mandatory clearing for certain categories of Swaps, incentives to shift Swap activity to exchange trading, margin and capital requirements, and other obligations designed to promote transparency. For non security-based Swaps including commodity Swaps, Dodd-Frank empowers the Commodity Futures Trading Commission (CFTC) to promulgate regulations implementing the law's objectives. The primary aim of Dodd-Frank is to regulate the key intermediaries in the Swaps market, which entities are either swap dealers (SDs), major swap participants (MSPs), and certain other financial entities, but the law also applies to a lesser degree to end-users of Swaps. On January 12, 2015, President Obama signed into law a bill that exempts from margin requirements Swaps used by end-users to hedge or mitigate commercial risk. Moreover, the CFTC's Dodd-Frank regulations preserve the ability of end users in the energy industry to hedge their risks using Swaps without being subject to mandatory clearing, and excepts or exempts end-users from many of the other substantive regulations. Accordingly, as an end-user, Generation is conducting its commercial business in a manner that does not require registration with the CFTC as an SD or MSP. Generation does not anticipate transacting in the future in a manner in which it would become a SD or MSP.

There are, however, some rulemakings that have not yet been finalized, including the capital and margin rules for (non-cleared) Swaps. Generation does not expect these rules to directly impact its collateral requirements. However, depending on the substance of these final rules in addition to certain international regulatory requirements still under development and that are similar to Dodd-Frank, Generation's Swap counterparties could be subject to additional and potentially significant capitalization requirements. These regulations could motivate the SDs and MSPs to increase collateral requirements or cash postings from their counterparties, including Generation.

Generation continues to monitor the rulemaking proceedings with respect to the capital and margin rules, but cannot predict to what extent, if any, further refinements to Dodd-Frank requirements may impact its cash flows or financial position, but such impacts could be material.

ComEd, PECO and BGE could also be subject to some Dodd-Frank requirements to the extent they were to enter into Swaps. However, at this time, management of ComEd, PECO and BGE continue to expect that their companies will not be materially affected by Dodd-Frank.

***Illinois Low Carbon Portfolio Standard (Exelon, Generation and ComEd).*** In March 2015, the Low Carbon Portfolio Standard (LCPS) was introduced in the Illinois General Assembly. The legislation would require ComEd and Ameren to purchase low carbon energy credits to match 70 percent of the electricity used on the distribution system. The LCPS is a technology-neutral solution, so all generators of zero or low carbon energy would be able to compete in the procurement process, including wind, solar, hydro, clean coal and nuclear. Costs associated with purchasing the low carbon energy credits would be collected from customers. The LCPS proposal includes consumer protection such as a price cap that would limit the impact to a 2.015% percent increase based off 2009 monthly bills, or about \$2 per month for the average residential electricity customer. The legislation also includes a separate customer rebate provision that would provide a direct bill credit to customers in the event wholesale prices exceed a specified level. If passed by the General Assembly, the legislation would be presented to the Governor, who would have 60 days to decide on the bill.

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**Legislation to Maximize Smart Grid Investments and to Promote a Cleaner and Greener Illinois (Exelon and ComEd).** In March 2015, legislation was introduced in the Illinois General Assembly that would (1) build on ComEd's investment in the Smart Grid to reinforce the resiliency and security of the electrical grid to withstand unexpected challenges, (2) expand energy efficiency programs to reduce energy waste and increase customer savings, (3) further integrate clean renewable energy onto the power system, and (4) introduce a new demand-based rate design for residential customers that would allow for a more equitable sharing of smart grid costs among customers. The legislation also provides for additional funding for customer assistance programs for low-income customers. If passed by the General Assembly, the legislation would be presented to the Governor, who would have 60 days to decide on the bill.

**Distribution Formula Rate Update Filing (Exelon and ComEd).** On April 15, 2015, ComEd filed its annual distribution formula rate with the ICC, reflecting a decreased revenue requirement of \$50 million, including an increase of \$92 million for the initial revenue requirement and a decrease of \$142 million related to the annual reconciliation for 2014. The filing establishes the revenue requirement used to set the rates that will take effect in January 2016 after the ICC's review and approval, which is due by December 2015. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to distribution formula update.

**2015 Pennsylvania Electric Distribution Rate Case (Exelon and PECO).** On March 27, 2015, PECO filed a petition with the PAPUC requesting an increase of \$190 million to its annual service revenues for electric delivery, which would reflect a 4.4% increase on the basis of total Pennsylvania jurisdictional operating revenue. The requested rate of return on common equity is 10.95%. The new electric delivery rates would take effect no later than January 1, 2016. The results of the rate case are expected to be known in the fourth quarter of 2015. PECO cannot predict how much of the requested increase the PAPUC will ultimately approve.

**Transmission Formula Rate Update Filing (Exelon, ComEd and BGE).** On April 15, 2015, ComEd filed its annual transmission formula rate update with the FERC, reflecting an increased revenue requirement of \$91 million, including an increase of \$73 million for the initial revenue requirement and an increase of \$18 million related to the annual reconciliation for 2014. The filing establishes the revenue requirement used to set rates that will take effect in June 2015, subject to review by the FERC and other parties, which is due by October 2015. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to transmission formula update.

In April 2015, BGE filed its annual transmission formula rate update with the FERC, reflecting an increased revenue requirement of \$10 million, including an increase of \$13 million for the initial revenue requirement and a decrease of \$3 million related to the annual reconciliation for 2014. The filing establishes the revenue requirement used to set rates that will take effect in June 2015, subject to review by the FERC and other parties, which is due by October 2015. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for further information related to the transmission formula update.

**Grand Prairie Gateway Transmission Line (Exelon and ComEd).** On December 2, 2013, ComEd filed a request to obtain the ICC's approval to construct a 60-mile overhead 345kV transmission line that traverses Ogle, DeKalb, Kane and DuPage Counties in Northern Illinois. On May 28, 2014, in a separate proceeding, FERC issued an order granting ComEd's request to include 100% of the capital costs recorded to construction work in progress during construction of the line in ComEd's transmission rate base. If the project is cancelled or abandoned for reasons beyond ComEd's control, FERC approved the ability for ComEd to recover 100% of its prudent costs incurred after May 21, 2014 and 50% of its costs incurred prior to May 21, 2014 in ComEd's transmission rate base. The costs incurred for the project prior to May 21, 2014 are immaterial. On October 22, 2014, the ICC issued an order approving ComEd's Grand Prairie Gateway Project over the objection of numerous landowners and the City of Elgin. On January 15, 2015, the City of Elgin and other parties filed a Notice of Appeal in the Illinois Appellate Court. On April 8, 2015, the ICC issued a rehearing order denying the appeals filed to consider an alternate route for the transmission line. The rehearing order affirmed the route approved within the ICC's October 22, 2014 order. ComEd expects to begin construction of the line in the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

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***FERC Ameren Order (Exelon and ComEd).*** In July 2012, FERC issued an order to Ameren Corporation (Ameren) finding that Ameren had improperly included acquisition premiums/goodwill in its transmission formula rate, particularly in its capital structure and in the application of AFUDC. FERC also directed Ameren to make refunds for the implied increase in rates in prior years. Ameren filed for rehearing of the July 2012 order, which was denied in June 2014. FERC and Ameren are in the process of determining the amount of any potential refund. ComEd believes that the FERC order authorizing its transmission formula rate is distinguishable from the circumstances that led to the July 2012 FERC order in the Ameren case. However, if ComEd were required to exclude acquisition premiums/goodwill from its transmission formula rate, the impact could be material to ComEd's results of operations and cash flows.

***FERC Order No. 1000 Compliance (ComEd, PECO and BGE).*** In FERC Order No. 1000, the FERC required public utility transmission providers to enhance their transmission planning procedures and their cost allocation methods applicable to certain new regional and interregional transmission projects. As part of the changes to the transmission planning procedures, the FERC required removal from all FERC-approved tariffs and agreements of a right of first refusal to build certain new transmission facilities. In compliance with the regional transmission planning requirements of Order No. 1000, PJM as the transmission provider submitted a compliance filing to FERC on October 25, 2012. On the same day, certain of the PJM transmission owners, including ComEd, PECO and BGE (collectively, the PJM Transmission Owners), submitted a filing asserting that their contractual rights embodied in the PJM governing documents continue to justify their right of first refusal to construct new reliability (and related) transmission projects and that the FERC should not be allowed to override such rights absent a showing that it is in the public interest to do so under the FERC's *Mobile-Sierra* standard of review. This is a heightened standard of review which the PJM Transmission Owners argued could not be satisfied based on the facts applicable to them. On March 22, 2013, FERC issued an order on the PJM Compliance Filing and the filing of these PJM Transmission Owners (1) rejecting the arguments of those PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard, (2) accepting most of the PJM filing, removing the right-of-first refusal from the PJM tariffs, and (3) directing PJM to remove certain exceptions that it included in its compliance filing that FERC found did not comply with Order No. 1000. FERC's order could enable third parties to seek to build certain regional transmission projects that had previously been reserved for the PJM Transmission Owners, potentially reducing ComEd's, PECO's and BGE's financial return on new investments in energy transmission facilities. Numerous parties sought rehearing of the FERC's March 22, 2013 order, including the PJM Transmission Owners who sought rehearing of the FERC's rejection of their *Mobile-Sierra* and related arguments. PJM's compliance filing was made on July 22, 2013. On May 15, 2014, FERC denied the rehearing requests except with respect to one issue on when PJM could consider state and local laws in evaluating projects. FERC generally accepted the July 22, 2013, Compliance Filing but required several minor additional changes. FirstEnergy and at least one other party filed an appeal of the May 15, 2014, Order upholding PJM's right of first refusal language in the DC Circuit. Exelon has intervened in the FirstEnergy appeal. Several parties have filed requests for rehearing or clarification concerning the changes set forth in the May 15, 2014, Order. On January 22, 2015, FERC issued an order denying rehearing in part and requiring further changes by PJM. On December 18, 2014, FERC issued an order conditionally accepting part of the PJM-MISO interregional Order No. 1000 compliance filing, rejecting a MISO proposal concerning cost allocation for cross-border reliability projects and directing a further compliance filing by PJM and MISO.

***FERC Transmission Complaint (Exelon and BGE).*** On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the PHI companies relating to their respective transmission formula rates. BGE's formula rate includes a 10.8% base rate of return on common equity (ROE) and a 50 basis point incentive for participating in PJM (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint.



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On August 21, 2014, FERC issued an order in the BGE and PHI companies' proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

On December 8, 2014, various state agencies in Delaware, Maryland, New Jersey, and D.C. filed a second complaint against BGE regarding the base ROE of the transmission business seeking a reduction from 10.8% to 8.8%. The filing of the second complaint creates a second refund window. By order issued on February 9, 2015, FERC established a hearing on the second complaint with the complainants' requested refund effective date of December 8, 2014. On February 20, 2015, the Chief Judge issued an order consolidating the two complaint proceedings and established an Initial Decision issuance deadline of February 29, 2016. On March 2, 2015, the Presiding Administrative Law Judge issued an order establishing a procedural schedule for the consolidated proceedings that provides for the hearing to commence on October 20, 2015.

Based on the current status of the complaint filings, BGE believes it is probable that BGE's base ROE rate will be adjusted, and that a refund to customers of transmission revenue for the two maximum fifteen month periods will be required. However, BGE is unable to estimate the most likely refund amount for either complaint at this time, and has therefore established a reserve, which is not material, representing the low end of a reasonably possible estimated range of loss. Additionally, management is unable to estimate the maximum exposure of a potential refund at this time, which may have a material impact on BGE's results of operations and cash flows. The estimated annual ongoing reduction in revenues if FERC approved the ROEs requested by the parties in their filings is approximately \$11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% as sought in the first complaint (while retaining the 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment), the result of the first fifteen month refund window would be a refund to customers of approximately \$13 million. If FERC were to order a reduction in BGE's base ROE to 8.8% as sought in the second complaint (while retaining 50 basis points of any incentives that were credited to the base return on equity for certain new transmission investment) and the refund period extended for a full fifteen months, the result would be a refund to customers of approximately \$14 million. See Note 5 - Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

***The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE).*** In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; which took effect June 1, 2013. Under the new law, following a proceeding before the MDPSC and with the MDPSC's approval of the eligible infrastructure replacement projects along with a corresponding surcharge, BGE could begin charging gas customers a monthly surcharge for infrastructure costs incurred after June 1, 2013. The legislation includes caps on the monthly surcharges to residential and non-residential customers, and would require an annual true-up of the surcharge revenues against actual expenditures. Investment levels in excess of the cap would be recoverable in a subsequent gas base rate proceeding at which time all costs for the infrastructure replacement projects would be rolled into gas distribution rates. Irrespective of the cap, BGE is required to file a gas rate case every five years under this legislation. On August 2, 2013, BGE filed its infrastructure replacement plan and associated surcharge. On January 29, 2014, the MDPSC issued a decision conditionally approving the first five years of BGE's plan and surcharge. On March 26, 2014, the MDPSC approved as filed BGE's proposed 2014 project list, tariff and associated surcharge amounts, with a surcharge that became effective April 1, 2014. On November 17, 2014, BGE filed a surcharge update including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and cost estimates to be included in the 2015 surcharge. The filing was approved with a revised

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surcharge effective January 1, 2015. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015. As of March 31, 2015, BGE recorded a regulatory asset of \$1 million, representing the difference between the surcharge revenues and program costs.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE's infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE's infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. The Court of Special Appeals has issued a preliminary procedural schedule that sets oral argument in this matter for a date in the first two weeks of November 2015. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

***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. The FERC orders approving the MOPR were upheld by the United States Court of Appeals for the Third Circuit in February 2014.

Exelon continues to work with PJM stakeholders and through the FERC process to implement several proposed changes to the PJM tariff aimed at ensuring that capacity resources (including those with state-sanctioned subsidy contracts and capacity market speculators) cannot inappropriately affect capacity auction prices in PJM.

***Reliability Pricing Model (Exelon, Generation and BGE).*** PJM's RPM Base Residual Auctions take place approximately 36 months ahead of the scheduled delivery year. The most recent auction, for the delivery year ending May 31, 2018, occurred in May 2014. On December 12, 2014, PJM filed proposed revisions to its tariff to revise the PJM capacity market through the new Capacity Performance product. PJM proposed to implement Capacity Performance for the May 2015 base residual auction, but FERC issued a deficiency letter on the Capacity Performance Filing and PJM has now sought authorization to delay the 2015 Base Residual Auction until such time that FERC is able to rule on the merits of the Capacity Performance proposal. Under Capacity Performance, PJM proposes to redefine the capacity product, which would require resources to provide an enhanced assurance of delivery of energy and reserves during emergency conditions. It also would increase penalties on resources for non-performance and eliminate many excuses for non-performance. Under the PJM proposal, these changes would take effect for capacity in the 2018/2019 delivery year. Exelon filed comments in support of the PJM proposal, but also proposed several modifications to the PJM proposal including increasing the penalty rate for non-performance, increasing the amount of Capacity Performance that PJM procures for the 2016/2017 and 2017/2018 Delivery Years and making the mitigation mechanism less administratively burdensome and more reflective of risks facing resources that provide the Capacity Performance product.

**Employees**

During the first quarter of 2015, Generation successfully ratified the collective bargaining agreement (CBA) with the Security Officer union at Clinton through 2021, and the CBA with the Security Officer union at Braidwood through 2018. In addition, two union contracts at Mystic 7 and Mystic 8, 9 were successfully negotiated and ratified through 2021.

**Critical Accounting Policies and Estimates**

Management of each of the Registrants makes a number of significant estimates, assumptions and judgments in the preparation of its financial statements. See ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - CRITICAL ACCOUNTING POLICIES AND ESTIMATES in Exelon's, Generation's, ComEd's, PECO's and BGE's

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combined 2014 Form 10-K for a discussion of the estimates and judgments necessary in the Registrants' accounting for AROs, goodwill, purchase accounting, unamortized energy assets and liabilities, asset impairments, depreciable lives of property, plant and equipment, defined benefit pension and other postretirement benefits, regulatory accounting, derivative instruments, taxation, contingencies, revenue recognition, and allowance for uncollectible accounts. At March 31, 2015, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2014.

**Results of Operations****Net Income Attributable to Common Shareholders by Registrant**

	Three Months Ended March 31,		Favorable (Unfavorable)
	2015 <sup>(a)</sup>	2014	Variance
Exelon	\$ 693	\$ 90	\$ 603
Generation	443	(185)	628
ComEd	90	98	(8)
PECO	139	89	50
BGE	106	85	21

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.

**Results of Operations - Generation**

	Three Months Ended March 31,		Favorable (Unfavorable)
	2015 <sup>(a)</sup>	2014	Variance
<b>Operating revenues</b>	\$ 5,840	\$ 4,390	\$ 1,450
<b>Purchased power and fuel expense</b>	3,433	3,357	(76)
<b>Revenue net of purchased power and fuel<sup>(b)</sup></b>	2,407	1,033	1,374
<b>Other operating expenses</b>			
Operating and maintenance	1,311	1,087	(224)
Depreciation and amortization	254	211	(43)
Taxes other than income	122	105	(17)
Total other operating expenses	1,687	1,403	(284)
<b>Equity in losses of unconsolidated affiliates</b>		(19)	19
<b>Gain (loss) on sales of assets</b>	(1)	5	(6)
<b>Operating income</b>	719	(384)	1,103
<b>Other income and (deductions)</b>			
Interest expense	(102)	(85)	(17)
Other, net	94	85	9
Total other income and (deductions)	(8)		(8)

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<b>Income (loss) before income taxes</b>	711	(384)	1,095
<b>Income taxes</b>	226	(199)	(425)
<b>Net income (loss)</b>	485	(185)	670
Net income attributable to noncontrolling interests	42		(42)
<b>Net income (loss) attributable to membership interest</b>	\$ 443	\$ (185)	\$ 628

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- (a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.
- (b) 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 (Loss) Attributable to Membership Interest***

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* Generation's net income (loss) attributable to membership interest for the three months ended March 31, 2015 increased compared to the same period in 2014 primarily due to higher revenue net of purchased power and fuel expense, partially offset by an increase in operating and maintenance expense and income taxes. The increase in revenue net of purchased power and fuel expense primarily relates to the inclusion of CENG's results on a fully consolidated basis in 2015, the inclusion of Integrys' results in 2015, the benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), the cancellation of the DOE spent nuclear disposal fee and mark-to-market gains in 2015 compared to mark-to-market losses in 2014, partially offset by a reduction in capacity credits and lower margins resulting from the 2014 sales of generating assets, lower realized energy prices and the absence of the 2014 fuel optimization opportunities in the South. The increase in operating and maintenance expense is primarily related to the inclusion of CENG's results on a fully consolidated basis in 2015. The increase in income taxes is primarily due to mark-to-market gains recorded in 2015 compared to market-to-market losses recorded in 2014.

***Revenue Net of Purchased Power and Fuel Expense***

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

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

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

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

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

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

Other Power Regions not considered individually significant:

South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes

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operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.

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

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

The following business activities are not allocated to a region, and are reported under Other: retail and wholesale gas, investments in gas and oil exploration and production activities, proprietary trading, compressed natural gas fueling stations, energy efficiency and cogeneration projects, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, indoor quality systems and home improvements, and investments in energy-related proprietary technology. Further, the following activities are not allocated to a region, and are reported in Other: unrealized mark-to-market impact of economic hedging activities; amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions and other miscellaneous revenues.

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

For the three months ended March 31, 2015 and 2014, Generation's revenue net of purchased power and fuel expense by region were as follows:

	<b>Three Months Ended March 31,</b>			
	<b>2015<sup>(a)</sup></b>	<b>2014</b>	<b>Variance</b>	<b>% Change</b>
Mid-Atlantic <sup>(b)(f)</sup>	\$ 782	\$ 695	\$ 87	12.5%
Midwest <sup>(c)</sup>	700	556	144	25.9%
New England	158	136	22	16.2%
New York <sup>(f)</sup>	188	(21)	209	n.m.
ERCOT	55	83	(28)	(33.7)%
Other Power Regions <sup>(d)</sup>	46	105	(59)	(56.2)%
<b>Total electric revenue net of purchased power and fuel expense</b>	<b>1,929</b>	<b>1,554</b>	<b>375</b>	<b>24.1%</b>
Proprietary trading	4	14	(10)	(71.4)%
Mark-to-market gains (losses)	162	(730)	892	122.2%
Other <sup>(e)</sup>	312	195	117	60.0%
<b>Total revenue net of purchased power and fuel expense</b>	<b>\$ 2,407</b>	<b>\$ 1,033</b>	<b>\$ 1,374</b>	<b>133.0%</b>

- (a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.
- (b) Results of transactions with PECO and BGE are included in the Mid-Atlantic region.
- (c) Results of transactions with ComEd are included in the Midwest region.
- (d) Other Power Regions include South, West and Canada, which are not considered individually significant.
- (e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes amortization of intangible assets related to commodity contracts recorded at fair value of \$38 million increase and \$42 million decrease in revenue net of purchased power and fuel expense for the three months ended March 31, 2015 and 2014, respectively.
- (f) Includes \$113 million and \$169 million of purchased power from CENG prior to its consolidation on April 1, 2014 in the Mid-Atlantic and New York Regions, respectively, for the three months ended March 31, 2014.

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Generation's supply sources by region are summarized below:

Supply source (GWh)	Three Months Ended March 31,		Variance	% Change
	2015	2014		
<b>Nuclear Generation</b>				
Mid-Atlantic <sup>(a)</sup>	15,718	12,136	3,582	29.5%
Midwest	22,427	23,125	(698)	(3.0)%
New York <sup>(a)</sup>	4,512		4,512	n.m.
<b>Total Nuclear Generation</b>	<b>42,657</b>	<b>35,261</b>	<b>7,396</b>	<b>21.0%</b>
<b>Fossil and Renewables<sup>(a)</sup></b>				
Mid-Atlantic	559	3,207	(2,648)	(82.6)%
Midwest	432	417	15	3.6%
New England	600	1,734	(1,134)	(65.4)%
New York	1	1		%
ERCOT	1,422	1,656	(234)	(14.1)%
Other Power Regions <sup>(c)</sup>	1,973	1,630	343	21.0%
<b>Total Fossil and Renewables</b>	<b>4,987</b>	<b>8,645</b>	<b>(3,658)</b>	<b>(42.3)%</b>
<b>Purchased Power</b>				
Mid-Atlantic <sup>(b)</sup>	1,824	3,233	(1,409)	(43.6)%
Midwest	589	711	(122)	(17.2)%
New England	6,408	2,070	4,338	n.m.
New York <sup>(b)</sup>		2,857	(2,857)	(100.0)%
ERCOT	2,244	2,153	91	4.2%
Other Power Regions <sup>(c)</sup>	3,307	3,355	(48)	(1.4)%
<b>Total Purchased Power</b>	<b>14,372</b>	<b>14,379</b>	<b>(7)</b>	<b>%</b>
<b>Total Supply/Sales by Region<sup>(d)</sup></b>				
Mid-Atlantic <sup>(e)</sup>	18,101	18,576	(475)	(2.6)%
Midwest <sup>(e)</sup>	23,448	24,253	(805)	(3.3)%
New England	7,008	3,804	3,204	84.2%
New York	4,513	2,858	1,655	57.9%
ERCOT	3,666	3,809	(143)	(3.8)%
Other Power Regions <sup>(c)</sup>	5,280	4,985	295	5.9%
<b>Total Supply/Sales by Region</b>	<b>62,016</b>	<b>58,285</b>	<b>3,731</b>	<b>6.4%</b>

- (a) Includes the proportionate share of output where Generation has an undivided ownership interest in jointly-owned generating plants and includes the total output of plants that are fully consolidated (e.g. CENG). Nuclear generation for the three months ended March 31, 2015 includes physical volumes of 3,284 GWh in the Mid-Atlantic region and 4,512 GWh in the New York region for CENG. Prior to the integration date of April 1, 2014, CENG volumes were included in purchased power.
- (b) Purchased power for the three months ended March 31, 2014 includes physical volumes of 2,489 GWh in the Mid-Atlantic and 2,857 GWh in the New York regions as a result of the PPA with CENG. As of the integration date of April 1, 2014, CENG volumes are included in nuclear generation.
- (c) Other Power Regions include South, West and Canada, which are not considered individually significant.
- (d) Excludes physical proprietary trading volumes of 1,808 GWh and 2,494 GWh for the three months ended March 31, 2015 and 2014, respectively.
- (e) Includes affiliate sales to PECO and BGE in the Mid-Atlantic region and affiliate sales to ComEd in the Midwest region.
- Mid-Atlantic*



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*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$87 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the

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consolidation of CENG, benefit of lower cost to serve load (including the absence of higher procurement costs for replacement power in 2014), higher nuclear volumes (excluding CENG), and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower capacity revenues, lower generation volumes due to the sale of Keystone and Conemaugh, and lower realized energy prices.

*Midwest*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$144 million increase in revenue net of purchased power and fuel expense in the Midwest was primarily due to higher capacity revenues, the acquisition of Integrys Energy Services, Inc., and the cancellation of the DOE spent nuclear fuel disposal fee, partially offset by lower nuclear volumes.

*New England*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$22 million increase in revenue net of purchased power and fuel expense in New England was primarily due to the benefit of lower cost to serve load and higher generation volumes from power purchase agreements, partially offset by lower generation volumes due to the sale of Fore River.

*New York*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$209 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the consolidation of CENG.

*ERCOT*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$28 million decrease in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower realized energy prices and lower generation volumes due to the sale of Quail Run.

*Other Power Regions*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$59 million decrease in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to lower realized energy prices and the absence of the 2014 fuel optimization opportunities.

*Mark-to-market*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* Generation is exposed to market risks associated with changes in commodity prices and enters into economic hedges to mitigate exposure to these fluctuations. Mark-to-market gains on economic hedging activities were \$162 million for the three months ended March 31, 2015 compared to losses of \$730 million for the three months ended March 31, 2014. See Notes 7 Fair Value of Financial Assets and Liabilities and 8 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

*Other*

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The \$117 million increase in other revenue net of purchased power and fuel expense was primarily driven by the amortization of contracts recorded at fair value during prior acquisitions, and the addition of Integrys Energy Services, Inc.

**Table of Contents***Nuclear Fleet Capacity Factor and Production Costs*

The following table presents nuclear fleet operating data for the three months ended March 31, 2015 as compared to the same periods in 2014, for the Generation-operated plants. The nuclear fleet capacity factor presented in the table is defined as the ratio of the actual output of a plant over a period of time to its output if the plant had operated at full average annual mean capacity for that time period. Nuclear fleet production cost is defined as the costs to produce one MWh of energy, including fuel, materials, labor, contracting and other miscellaneous costs, but excludes depreciation, required capital investment, benefits costs associated with labor, insurance, property taxes, unit contingent costs, suspended DOE nuclear waste storage fee, and certain other non-production related overhead costs. Generation considers capacity factor and production costs useful measures comparatively 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.

	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
Nuclear fleet capacity factor <sup>(a)</sup>	92.7%	94.1%
Nuclear fleet production cost per MWh <sup>(a)</sup>	\$ 20.55	\$ 20.71

(a) Excludes Salem, which is operated by PSEG Nuclear, LLC. Reflects ownership percentage of stations operated by Exelon. On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet, and as a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of unplanned outage days and non-outage energy losses during the three months ended March 31, 2015 compared to the same period in 2014. For the three months ended March 31, 2015 and 2014, refueling outage days totaled 89 (of which 41 are related to CENG plants) and 52, respectively, with the increase primarily attributable to the inclusion of CENG in 2015. During the same periods, non-refueling outage days totaled 32 (of which 5 were related to CENG) and 20, respectively. Production costs per MWh were lower for the three months ended March 31, 2015 as compared to the same period in 2014, due to the elimination of the SNF disposal fee in 2014, partially offset by the inclusion of CENG.

***Operating and Maintenance***

The changes in operating and maintenance expense for the three months ended March 31, 2015 compared to the same period in 2014, consisted of the following:

	<b>Three Months Ended March 31,</b>	
	<b>Increase (Decrease)<sup>(a)</sup></b>	
Labor, other benefits, contracting, materials	\$	141
Nuclear refueling outage costs, including the co-owned Salem plants <sup>(b)</sup>		44
Accretion expense		23
Regulatory fees and assessment		17
Corporate allocations <sup>(c)</sup>		7
Merger and integration costs		(2)
Pension and non-pension postretirement benefits expense		(7)
Midwest Generation bankruptcy recoveries		(14)
Other		15
Increase in operating and maintenance expense	\$	224



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- (a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.
- (b) Reflects the impact of increased refueling outage days in 2015, due to the inclusion of CENG.
- (c) Reflects an increased share of corporate allocated costs primarily due to the CENG integration in the second quarter of 2014.

**Depreciation and Amortization**

The increase in depreciation and amortization expense for the three months ended March 31, 2015 compared to the three months ended March 31, 2014 is primarily due the inclusion of CENG's results.

**Taxes Other Than Income**

The increase in taxes other than income for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014 is primarily due to the inclusion of CENG's results.

**Equity in Losses of Unconsolidated Affiliates**

The decrease in equity in losses of unconsolidated affiliates for the three months ended March 31, 2015 as compared to the three months ended March 31, 2014 is primarily due to CENG's operating results being fully consolidated beginning April 1, 2014 and, as a result, are not reflected as equity method earnings in 2015.

**Gain (Loss) on Sales of Assets**

The unfavorable change in gain (loss) on sales of assets is primarily due to decreased asset divestiture activity in 2015.

**Interest Expense**

The increase in interest expense for three months ended March 31, 2015 compared to same period in 2014 is primarily due to higher outstanding debt in 2015.

**Other, Net**

The increase in Other, net for the three months ended March 31, 2015 compared to the same period in 2014 primarily reflects the change in the realized and unrealized gains and losses related to the NDT funds of its Non-Regulatory Agreement Units as described in the table below. Other, net also reflects \$23 million and \$20 million for the three months ended March 31, 2015 and 2014, respectively, related to the contractual elimination of income tax expense (benefit) associated with the NDT funds of the Regulatory Agreement Units. Refer to Note 11 Nuclear Decommissioning for additional information regarding NDT funds. The increase in Other, net was also partially offset by a benefit recorded in 2014 for the favorable settlement of certain income tax positions on Constellation's 2009-2012 pre-acquisition tax returns.

The following table provides unrealized and realized gains on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three months ended March 31, 2015 and 2014:

	<b>Three Months Ended March 31,</b>	
	<b>2015<sup>(a)</sup></b>	<b>2014</b>
Net unrealized gains on decommissioning trust funds	\$ 40	\$ 13
Net realized gains on sale of decommissioning trust funds	6	13

- (a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 financial results include CENG's results of operations on a fully consolidated basis.



**Table of Contents****Effective Income Tax Rate**

The effective income tax rate was 31.8% for the three months ended March 31, 2015, respectively, compared to 51.8% for the same period during 2014. See Note 10 – Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in the effective income tax rate.

**Results of Operations – ComEd**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2015	2014	
<b>Operating revenue</b>	\$ 1,185	\$ 1,134	\$ 51
<b>Purchased power expense</b>	327	320	(7)
<b>Revenue net of purchased power expense<sup>(a)</sup></b>	858	814	44
<b>Other operating expenses</b>			
Operating and maintenance	378	326	(52)
Depreciation and amortization	175	173	(2)
Taxes other than income	75	77	2
Total other operating expenses	628	576	(52)
<b>Operating income</b>	230	238	(8)
<b>Other income and (deductions)</b>			
Interest expense, net	(84)	(80)	(4)
Other, net	3	5	(2)
Total other income and (deductions)	(81)	(75)	(6)
<b>Income before income taxes</b>	149	163	(14)
<b>Income taxes</b>	59	65	6
<b>Net income</b>	\$ 90	\$ 98	\$ (8)

(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**

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* ComEd's net income for the three months ended March 31, 2015 was lower than the same period in 2014, primarily due to unfavorable weather and volume. Electric distribution earnings were flat, reflecting the impacts of increased capital investment, offset by lower allowed return on common equity due to a decrease in treasury rates.

**Operating Revenue Net of Purchased Power Expense**

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There are certain drivers of Operating revenue that are fully offset by their impact on Purchased power expense, such as commodity procurement costs and participation in customer choice programs. ComEd is permitted to recover electricity procurement costs from retail customers without mark-up. Therefore, fluctuations



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in electricity procurement costs have no impact on revenue net of purchased power expense. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information on ComEd's electricity procurement process.

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

The number of retail customers participating in customer choice programs was 2,406,289 and 2,655,909 at March 31, 2015, and 2014, representing 62% and 69% of total retail customers, respectively. Retail energy purchased from competitive electric generation suppliers represented 78% and 80% of ComEd's retail kWh sales at March 31, 2015, and 2014, respectively.

The City of Chicago currently participates in ComEd's customer choice program and purchases electricity from Constellation (formerly Integrys). Beginning in September 2015, the City of Chicago will no longer participate in the customer choice program and will begin purchasing its electricity from ComEd. It is anticipated that by the end of the fourth quarter 2015 approximately 45% of retail customers and 73% of kWh sales in the ComEd service territory will be supplied by competitive retail electric suppliers, reflecting the City of Chicago switching back to ComEd. ComEd's Operating revenue will increase as a result of the City of Chicago switching, but will be fully offset in Purchased power expense.

The changes in ComEd's Revenue net of purchased power expense for the three months ended March 31, 2015, compared to the same period in 2014 consisted of the following:

	<b>Increase (Decrease)</b>
Weather	\$ (5)
Volume	(7)
Electric distribution revenue	6
Transmission revenue	4
Regulatory required programs	8
Uncollectible accounts recovery, net	32
Pricing and customer mix	7
Other	(1)
<b>Increase in revenue net of purchased power expense</b>	<b>\$ 44</b>

*Weather.* The demand for electricity is affected by weather conditions. Very warm weather in summer months and very cold weather in other months are referred to as favorable weather conditions because these weather conditions result in increased customer usage. Conversely, mild weather reduces demand. For the three months ended March 31, 2015, unfavorable weather conditions reduced Operating revenue net of purchased power expense when compared to the same period in 2014.

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Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in ComEd's service territory with cooling degree days generally having a more significant impact to ComEd, particularly during the summer months. The changes in heating and cooling degree days in ComEd's service territory for the three months ended March 31, 2015, and 2014, consisted of the following:

Heating and Cooling Degree-Days	Three Months Ended			% Change	
	2015	2014	Normal	From 2014	From Normal
Heating Degree-Days	3,632	3,874	3,164	(6.2)%	14.8%
Cooling Degree-Days				n/a	n/a

*Volume.* Revenue net of purchased power expense decreased as a result of lower delivery volume, exclusive of the effects of weather, reflecting decreased average usage per customer as compared to the same three month period in 2014.

*Electric Distribution Revenue.* EIMA provides for a performance-based rate formula, which requires an annual reconciliation of the revenue requirement in effect to the actual costs that the ICC determines are prudently and reasonably incurred in a given year. Under EIMA, distribution revenue varies from year to year based on fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. In addition, ComEd's allowed rate of return on common equity is the annual average rate of 30-year treasury notes plus 580 basis points, subject to a collar of plus or minus 50 basis points. Therefore, the collar limits favorable and unfavorable impacts of weather and load on distribution revenue. During the three months ended March 31, 2015, ComEd recorded increased electric distribution revenue primarily due to higher operating and maintenance expense and increased capital investment, partially offset by lower allowed return on common equity due to a decrease in treasury rates. See Operating and Maintenance Expense below, and Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's rate formula pursuant to EIMA.

*Transmission Revenue.* Under a FERC-approved formula, transmission revenue varies from year to year based on fluctuations in the underlying costs, investments being recovered and other billing determinants, such as the highest daily peak load from the previous calendar year. For the three months ended March 31, 2015, ComEd recorded increased transmission revenue due to increased capital investment. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information.

*Regulatory Required Programs.* This represents the change in Operating revenue collected under approved riders to recover costs incurred for regulatory programs such as ComEd's energy efficiency and demand response and purchased power administrative costs. The riders are designed to provide full and current cost recovery. An equal and offsetting amount has been included in Operating and maintenance expense. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

*Uncollectible Accounts Recovery, Net.* Uncollectible accounts recovery, net represents recoveries under ComEd's uncollectible accounts tariff. See the Operating and maintenance expense discussion below for additional information on this tariff.

*Pricing and Customer Mix.* The increase in Revenue net of purchased power as a result of pricing and customer mix is primarily attributable to higher overall effective rates due to decreased usage across all major customer classes and change in customer mix for the three months ended March 31, 2015, as compared to the same period in 2014.

*Other.* Other revenue, which can vary period to period, includes rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of environmental costs associated with MGP sites, for which an equal and offsetting amount is reflected in Depreciation and amortization expense during the periods presented.

**Table of Contents****Operating and Maintenance Expense**

	Three Months Ended March 31,		Increase
	2015	2014	
Operating and maintenance expense baseline	\$ 322	\$ 278	\$ 44
Operating and maintenance expense regulatory required program(s)	56	48	\$ 8
<b>Total operating and maintenance expense</b>	<b>\$ 378</b>	<b>\$ 326</b>	<b>\$ 52</b>

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

The changes in operating and maintenance expense for the three months ended March 31, 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease)
<b>Baseline</b>	
Labor, other benefits, contracting and materials <sup>(a)</sup>	\$ 16
Pension and non-pension postretirement benefits expense <sup>(b)</sup>	(8)
Storm-related costs	(4)
Uncollectible accounts expense provision <sup>(c)</sup>	1
Uncollectible accounts expense recovery, net	31
Other	8
	44
<b>Regulatory required programs</b>	
Energy efficiency and demand response programs	8
	8
<b>Increase in operating and maintenance expense</b>	<b>\$ 52</b>

(a) Primarily reflects increased contracting costs related to EIMA, and other preventative and corrective maintenance projects for the three months ended March 31, 2015. See Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements for additional information regarding EIMA.

(b) Primarily reflects decreased non-pension costs associated with OPEB plan design changes during the second quarter of 2014. See Note 16 Retirement Benefits of the Exelon 2014 Form 10-K for additional information regarding plan changes.

(c) ComEd is allowed to recover from or refund to customers the difference between the utility's annual uncollectible accounts expense and the amounts collected in rates annually through a rider mechanism. During the three months ended March 31, 2015, ComEd recorded a net increase in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting increase has been recognized in operating revenue for the periods presented.

**Depreciation and Amortization**

Depreciation and amortization expense increased during the three months ended March 31, 2015, compared to the same period in 2014, primarily due to increased capital expenditures, partially offset by decreased amortization as a result of ComEd's severance regulatory assets

fully amortizing during the second quarter of 2014.

***Taxes Other Than Income***

Taxes other than income taxes, which can vary period to period, include municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income taxes remained relatively flat during the three months ended March 31, 2015, compared to the same period in 2014.

**Table of Contents****Interest Expense, Net**

The changes in interest expense, net for the three months ended March 31, 2015, compared to the same period in 2014, consisted of the following:

	<b>Increase (Decrease)</b>
Interest expense related to uncertain tax positions	\$ (1)
Interest expense on debt (including financing trusts) <sup>(a)</sup>	3
Other	2
Increase in interest expense, net	\$ 4

(a) Primarily reflects an increase in interest expense due to the issuance of First Mortgage Bonds on November 10, 2014 and March 2, 2015. See Note 9 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

**Effective Income Tax Rate**

The effective income tax rate was 39.6% for the three months ended March 31, 2015 compared to 39.9% for the same period during 2014. See Note 10 Income Taxes 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**

<b>Retail Deliveries to Customers (in GWs)</b>	<b>Three Months Ended March 31,</b>		<b>% Change</b>	<b>Weather- Normal % Change</b>
	<b>2015</b>	<b>2014</b>		
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	6,997	7,411	(5.6)%	(3.2)%
Small commercial & industrial	8,161	8,331	(2.0)%	(0.4)%
Large commercial & industrial	6,877	7,095	(3.1)%	(2.2)%
Public authorities & electric railroads	379	397	(4.5)%	(2.8)%
Total retail deliveries	22,414	23,234	(3.5)%	(1.9)%

<b>Number of Electric Customers</b>	<b>As of March 31,</b>	
	<b>2015</b>	<b>2014</b>
Residential	3,511,271	3,488,204
Small commercial & industrial	369,424	367,282
Large commercial & industrial	1,966	2,028
Public authorities & electric railroads	4,843	4,852
Total	3,887,504	3,862,366

<b>Electric Revenue</b>	<b>Three Months Ended March 31,</b>		<b>% Change</b>
	<b>2015</b>	<b>2014</b>	

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<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$	568	\$ 508 11.8%
Small commercial & industrial		338	344 (1.7)%
Large commercial & industrial		109	115 (5.2)%
Public authorities & electric railroads		12	13 (7.7)%
Total retail		1,027	980 4.8%
Other revenue <sup>(b)</sup>		158	154 2.6%
Total electric revenue	\$	1,185	\$ 1,134 4.5%

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- (a) Reflects delivery revenue 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 and transmission.
- (b) Other revenue primarily includes transmission revenue from PJM. Other items include rental revenue, revenue related to late payment charges, revenue from other utilities for mutual assistance programs and recoveries of environmental costs associated with MGP sites.

**Results of Operations PECO**

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2015	2014	
<b>Operating revenue</b>	\$ 985	\$ 993	\$ (8)
Purchased power and fuel	438	464	26
<b>Revenue net of purchased power and fuel expense<sup>(a)</sup></b>	<b>547</b>	<b>529</b>	<b>18</b>
<b>Other operating expenses</b>			
Operating and maintenance	222	280	58
Depreciation and amortization	62	58	(4)
Taxes other than income	41	42	1
Total other operating expenses	325	380	55
<b>Gain on sale of assets</b>	<b>1</b>		<b>1</b>
<b>Operating income</b>	<b>223</b>	<b>149</b>	<b>74</b>
<b>Other income and (deductions)</b>			
Interest expense, net	(28)	(28)	
Other, net	2	2	
Total other income and (deductions)	(26)	(26)	
<b>Income before income taxes</b>	<b>197</b>	<b>123</b>	<b>74</b>
<b>Income taxes</b>	<b>58</b>	<b>34</b>	<b>(24)</b>
<b>Net income attributable to common shareholder</b>	<b>\$ 139</b>	<b>\$ 89</b>	<b>\$ 50</b>

- (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 Attributable to Common Shareholder**

*Three Months Ended March 31, 2015 Compared to Three Months Ended March 31, 2014.* The increase in net income attributable to common shareholder was driven primarily by a decrease in operating and maintenance expense due to a decrease in storm costs and favorable weather included in Revenue net of purchased power and fuel expense.

*Operating Revenue Net of Purchased Power and Fuel Expense*

Electric and gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. PECO's electric supply and natural gas cost rates charged to customers are subject to adjustments at least quarterly that are designed to recover or refund the difference between the actual cost of



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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 revenue net of purchased power and fuel expense.

Electric and gas revenue and purchased power and fuel expense are also affected by fluctuations in participation in the Customer Choice Program. All PECO customers have the choice to purchase electricity and gas from competitive electric generation and natural gas suppliers, respectively. The customer's choice of suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to supplied energy and natural gas service. Customer choice program activity has no impact on electric and gas revenue net of purchased power and fuel expense. The number of retail customers purchasing electricity from a competitive electric generation supplier was 551,000 and 545,000 at March 31, 2015 and 2014, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 67% and 68% of PECO's retail kWh sales for the three months ended March 31, 2015 and 2014, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 80,200 and 72,600 at March 31, 2015 and 2014, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 23% and 21% of PECO's mcf sales for the three months ended March 31, 2015 and 2014, respectively.

The changes in PECO's operating revenue net of purchased power and fuel expense for the three months ended March 31, 2015 compared to the same period in 2014 consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Weather	\$ 4	\$ 4	\$ 8
Volume	4	3	7
Pricing	(1)	1	
Regulatory required programs	5		5
Other	(3)	1	(2)
Total increase (decrease)	\$ 9	\$ 9	\$ 18

*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. During the three months ended March 31, 2015 compared to the same period in 2014, operating revenue net of purchased power and fuel expense was higher due to the impact of favorable winter weather conditions in PECO's service territory.

Heating and cooling degree days are quantitative indices that reflect the demand for energy needed to heat or cool a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three months ended March 31, 2015 compared to the same period in 2014 and normal weather consisted of the following:

	Three Months Ended			% Change	
	March 31,		Normal	From 2014	From Normal
Heating and Cooling Degree-Days	2015	2014	2,477	3.2%	18.4%
Heating Degree-Days	2,934	2,844			
Cooling Degree-Days			1	n/a	(100.0)%

*Volume.* The increase in operating revenue net of purchased power and fuel expense related to delivery volume, exclusive of the effects of weather, for the three months ended March 31, 2015 compared to the same period in 2014, primarily reflects the impact of moderate economic and customer growth partially offset by

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energy efficiency initiatives on customer usages for electric and gas and a shift in the volume profile across classes from lower priced classes to higher priced classes for electric.

*Pricing.* Pricing for the three months ended March 31, 2015 compared to the same period in 2014 remained relatively constant.

*Regulatory Required Programs.* This represents the change in operating revenue collected under approved riders to recover costs incurred for regulatory programs such as smart meter, energy efficiency and the GSA. The riders are designed to provide full and current cost recovery as well as a return. The costs of these programs are included in Operating and maintenance expense, Depreciation and amortization expense and Income taxes. Refer to the Operating and maintenance expense discussion below for additional information on included programs.

*Other.* Other revenue for electric primarily reflects the impact of lower wholesale transmission revenue for the three months ended March 31, 2015 compared to the same period in 2014. Wholesale transmission revenue is impacted by the previous year's peak demand, which was lower in 2014 than in 2013.

**Operating and Maintenance Expense**

	Three Months Ended March 31,		Increase (Decrease)
	2015	2014	
Operating and maintenance expense baseline	\$ 196	\$ 259	\$ (63)
Operating and maintenance expense regulatory required program <sup>(a)</sup>	26	21	5
Total operating and maintenance expense	\$ 222	\$ 280	\$ (58)

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

The changes in operating and maintenance expense for the three months ended March 31, 2015 compared to the same period in 2014, consisted of the following:

	Increase (Decrease)
Baseline	
Labor, other benefits, contracting and materials	\$ 13
Storm-related costs	(75) <sup>(a)</sup>
Pension and non-pension postretirement benefits expense	(1)
Uncollectible accounts expense	(2)
Other	2
	(63)
Regulatory required programs	
Smart meter	(1)
Energy efficiency	5
Other	1
	5
Increase in operating and maintenance expense	\$ (58)

(a) Reflects a reduction of \$66 million in incremental storm costs in the first quarter of 2015 as a result of the February 5, 2014 ice storm.

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***Depreciation and Amortization Expense***

The increase in depreciation and amortization expense for the three months ended March 31, 2015 compared to the same period in 2014 was primarily due to ongoing capital expenditures.

***Taxes Other Than Income***

Taxes other than income for the three months ended March 31, 2015 compared to the same period in 2014 remained relatively constant.

***Interest Expense, Net***

Interest expense, net for the three months ended March 31, 2015 compared to the same period in 2014 remained relatively constant.

***Other, Net***

Other, net for the three months ended March 31, 2015 compared to the same period in 2014 remained constant.

***Effective Income Tax Rate***

PECO's effective income tax rate was 29.4% and 27.6% for the three months ended March 31, 2015 and 2014, respectively. See Note 10 Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

**Table of Contents****PECO Electric Operating Statistics and Revenue Detail**

	Three Months Ended March 31,			Weather- Normal % Change
	2015	2014	% Change	
<b>Retail Deliveries to Customers (in GWhs)</b>				
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	3,968	3,848	3.1%	1.5%
Small commercial & industrial	2,162	2,055	5.2%	3.9%
Large commercial & industrial	3,734	3,777	(1.1)%	(1.5)%
Public authorities & electric railroads	228	259	(12.0)%	(12.0)%
Total retail deliveries	10,092	9,939	1.5%	0.4%

	As of March 31,	
	2015	2014
<b>Number of Electric Customers</b>		
Residential	1,439,005	1,428,798
Small commercial & industrial	149,192	149,285
Large commercial & industrial	3,102	3,114
Public authorities & electric railroads	9,771	9,671
Total	1,601,070	1,590,868

	Three Months Ended March 31,		
	2015	2014	% Change
<b>Electric Revenue</b>			
<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$ 450	\$ 444	1.4%
Small commercial & industrial	115	111	3.6%
Large commercial & industrial	53	63	(15.9)%
Public authorities & electric railroads	8	8	%
Total retail	626	626	%
Other revenue <sup>(b)</sup>	51	52	(1.9)%
Total electric revenue	\$ 677	\$ 678	(0.1)%

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

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

**Table of Contents****PECO Gas Operating Statistics and Revenue Detail**

Deliveries to Customers (in mmcf)	Three Months Ended March 31,		% Change	Weather- Normal % Change
	2015	2014		
<b>Retail Delivery</b>				
Retail sales <sup>(a)</sup>	34,863	33,170	5.1%	2.9%
Transportation and other	8,696	8,369	3.9%	(1.2)%
Total gas deliveries	43,559	41,539	4.9%	2.0%

Number of Gas Customers	As of March 31,	
	2015	2014
Residential	464,344	459,627
Commercial & industrial	42,941	42,385
Total retail	507,285	502,012
Transportation	847	898
Total	508,132	502,910

Gas Revenue	Three Months Ended March 31,		% Change
	2015	2014	
<b>Retail Sales</b>			
Retail sales <sup>(a)</sup>	\$ 296	\$ 302	(2.0)%
Transportation and other	12	13	(7.7)%
Total gas revenue	\$ 308	\$ 315	(2.2)%

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

**Table of Contents****Results of Operations** BGE

	Three Months Ended March 31,		Favorable (Unfavorable) Variance
	2015	2014	
<b>Operating revenue</b>	\$ 1,036	\$ 1,054	\$ (18)
<b>Purchased power and fuel</b>	487	529	42
<b>Revenue net of purchased power and fuel expense<sup>(a)</sup></b>	549	525	24
<b>Other operating expenses</b>			
Operating and maintenance	182	188	6
Depreciation and amortization	106	108	2
Taxes other than income	57	60	3
Total other operating expenses	345	356	11
<b>Operating income</b>	204	169	35
<b>Other income and (deductions)</b>			
Interest expense, net	(25)	(27)	2
Other, net	4	4	
Total other income and (deductions)	(21)	(23)	2
<b>Income before income taxes</b>	183	146	37
<b>Income taxes</b>	74	58	(16)
<b>Net income</b>	109	88	21
Preference stock dividends	3	3	
<b>Net income attributable to common shareholder</b>	\$ 106	\$ 85	\$ 21

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

**Net Income attributable to common shareholder**

*Three Months Ended March 31, 2015, Compared to Three Months Ended March 31, 2014.* BGE's net income attributable to common shareholder for the three months ended March 31, 2015 was higher than the same period in 2014, primarily due to an increase in revenue net of purchased power and fuel expense as a result of the December 2014 electric and gas distribution rate order issued by the MDPSC and an decrease in operating and maintenance expense.

**Operating Revenue Net of Purchased Power and Fuel Expense**

There are certain drivers to operating revenue that are offset by their impact on purchased power expense and fuel expense, such as commodity procurement costs and programs allowing customers to select a competitive electric or natural gas supplier. Electric and gas revenue and purchased power and fuel expense are affected by fluctuations in commodity procurement costs. BGE's electric and natural gas rates charged to

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customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.



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The number of customers electing to select a competitive electric generation supplier affects electric SOS revenue and purchased power expense. The number of customers electing to select a competitive natural gas supplier affects gas cost adjustment revenue and purchased natural gas expense. All BGE customers have the choice to purchase energy from a competitive electric generation supplier. This customer choice of electric generation suppliers does not impact the volume of deliveries, but affects revenue collected from customers related to SOS. The number of retail customers purchasing electricity from a competitive electric generation supplier was 355,000 and 394,100 at March 31, 2015 and 2014, respectively, representing 28% and 32% of total retail customers at March 31, 2015 and 2014, respectively. Retail deliveries purchased from competitive electric generation suppliers represented 56% and 58% of BGE's retail kWh sales for the three months ended March 31, 2015 and 2014, respectively. The number of retail customers purchasing natural gas from a competitive natural gas supplier was 158,000 and 172,200 at March 31, 2015 and 2014, respectively, representing 24% and 26% of total retail customers at March 31, 2015 and 2014, respectively. Retail deliveries purchased from competitive natural gas suppliers represented 45% and 47% of BGE's retail mmcf sales for the three months ended March 31, 2015 and 2014, respectively.

The changes in BGE's operating revenue net of purchased power and fuel expense for the three months ended March 31, 2015, compared to the same period in 2014, consisted of the following:

	Increase (Decrease)		
	Electric	Gas	Total
Distribution rate increase	\$ 9	\$ 16	\$ 25
Regulatory required programs	(4)	2	(2)
Other	1		1
<b>Total increase</b>	<b>\$ 6</b>	<b>\$ 18</b>	<b>\$ 24</b>

*Revenue Decoupling.* The demand for electricity and gas is affected by weather and usage conditions. The MDPSC has allowed BGE to record a monthly adjustment to its electric and gas distribution revenue from all residential customers, commercial electric customers, the majority of large industrial electric customers, and all firm service gas customers to eliminate the effect of abnormal weather and usage patterns per customer on BGE's electric and gas distribution volumes, thereby recovering a specified dollar amount of distribution revenue per customer, by customer class, regardless of changes in consumption levels. This means BGE recognizes revenue at MDPSC-approved levels per customer, regardless of what actual distribution volumes were for a billing period. Therefore, while these revenues are affected by customer growth, they will not be affected by actual weather or usage conditions. BGE bills or credits customers in subsequent months for the difference between approved revenue levels under revenue decoupling and actual customer billings.

Heating degree days are quantitative indices that reflect the demand for energy needed to heat a home or business. Normal weather is determined based on historical average heating and cooling degree days for a 30-year period in BGE's service territory. The changes in heating degree days in BGE's service territory for the three months ended March 31, 2015 compared to the same period in 2014 consisted of the following:

	Three Months Ended March 31,			% Change	
	2015	2014	Normal	From 2014	From Normal
Heating and Cooling Degree-Days					
Heating Degree-Days	2,950	2,861	2,395	3.1%	23.2%
Cooling Degree-Days				n/a	n/a

*Distribution Rate Increase.* The increase in distribution rates for the three months ended March 31, 2015, compared to the same period in 2014, was primarily due to the impact of the new electric and natural gas distribution rates charged to customers that became effective in December 2014 in accordance with the MDPSC

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approved electric and natural gas distribution rate case orders. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information.

*Regulatory Required Programs.* This represents the change in revenue collected under approved riders to recover costs incurred for the energy efficiency and demand response programs as well as administrative and commercial and industrial customer bad debt costs for SOS. The riders are designed to provide full recovery, as well as a return in certain instances. The costs of these programs are included in operating and maintenance expense, depreciation and amortization expense and taxes other than income taxes. The decrease in revenue related to regulatory required programs for the three months ended March 31, 2015 compared to the same period in 2014 was primarily due to the recovery of lower energy efficiency program costs.

*Other.* Other revenue increased during the three months ended March 31, 2015 compared to the same period in 2014. Other revenue, which can vary from period to period, includes miscellaneous revenue such as service application and late payment fees.

***Operating and Maintenance Expense***

The changes in operating and maintenance expense for the three months ended March 31, 2015 compared to the same period in 2014, consisted of the following:

	<b>Increase (Decrease)</b>
Storm-related costs	\$ (19)
Uncollectible accounts expense	14
Other	(1)
Increase in operating and maintenance expense	\$ (6)

***Depreciation and Amortization***

Depreciation and amortization expense decreased for the three months ended March 31, 2015 compared to the same period in 2014 primarily due to a reduction in regulatory asset amortization related to demand response programs.

***Taxes Other Than Income***

Taxes other than income decreased for the three months ended March 31, 2015 compared to the same period in 2014 primarily due to decreased gross receipts tax as a result of lower revenues and a decrease in payroll taxes.

***Interest Expense, Net***

Interest expense, net for the three months ended March 31, 2015 compared to the same period in 2014 remained relatively constant.

***Effective Income Tax Rate***

BGE's effective income tax rate was 40.4% for the three months ended March 31, 2015 as compared to 39.7% for the same period during 2014. See Note 10 Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

**Table of Contents****BGE Electric Operating Statistics and Revenue Detail**

Retail Deliveries to Customers (in GWhs)	Three Months Ended March 31,			Weather- Normal % Change
	2015	2014	% Change	
<b>Retail Deliveries<sup>(a)</sup></b>				
Residential	4,173	4,092	2.0%	n.m.
Small commercial & industrial	845	834	1.3%	n.m.
Large commercial & industrial	3,439	3,470	(0.9)%	n.m.
Public authorities & electric railroads	75	78	(3.8)%	n.m.
Total electric deliveries	8,532	8,474	0.7%	n.m.

Number of Electric Customers	As of March 31,	
	2015	2014
Residential	1,131,621	1,124,174
Small commercial & industrial	112,811	112,623
Large commercial & industrial	11,777	11,661
Public authorities & electric railroads	286	292
Total	1,256,495	1,248,750

Electric Revenue	Three Months Ended March 31,		
	2015	2014	% Change
<b>Retail Sales<sup>(a)</sup></b>			
Residential	\$ 449	\$ 436	3.0%
Small commercial & industrial	76	71	7.0%
Large commercial & industrial	120	123	(2.4)%
Public authorities & electric railroads	8	8	%
Total retail	653	638	2.4%
Other revenue	60	71	(15.5)%
Total electric revenue	\$ 713	\$ 709	0.6%

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

**Table of Contents****BGE Gas Operating Statistics and Revenue Detail**

Deliveries to Customers (in mmcf)	Three Months Ended			Weather-Normal % Change
	2015	March 31, 2014	% Change	
<b>Retail Deliveries<sup>(b)</sup></b>				
Retail sales	46,877	46,388	1.1%	n.m.
Transportation and other	3,325	6,330	(47.5)%	n.m.
Total gas deliveries	50,202	52,718	(4.8)%	n.m.
	<b>As of March 31,</b>			
<b>Number of Gas Customers</b>	<b>2015</b>	<b>2014</b>		
Residential	612,814	613,469		
Commercial & industrial	44,199	44,266		
Total	657,013	657,735		
	<b>Three Months Ended</b>			
<b>Gas Revenue</b>	<b>2015</b>	<b>2014</b>	<b>% Change</b>	
<b>Retail Sales<sup>(b)</sup></b>				
Retail sales	\$ 299	\$ 285	4.9%	
Transportation and other <sup>(c)</sup>	24	60	(60.0)%	
Total gas revenue	\$ 323	\$ 345	(6.4)%	

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

(c) Transportation and other gas revenue includes off-system revenue of 3,325 mmcf (\$23 million) and 6,330 mmcf (\$53 million) for the three months ended March 31, 2015 and 2014, respectively.

**Liquidity and Capital Resources**

Exelon's and Generation's prior year activity presented below includes the activity of CENG from the integration date effective April 1, 2014 through December 31, 2014. All results included throughout the liquidity and capital resources section are presented on a GAAP basis.

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 Corporate, Generation, ComEd, PECO and BGE have access to unsecured revolving credit facilities with aggregate bank commitments of \$0.5 billion, \$5.3 billion, \$1.0 billion, \$0.6 billion and \$0.6 billion, respectively. Exelon Corporate, Generation, ComEd, PECO and BGE's revolving credit facilities expire in 2018 and 2019. In addition, Generation has \$0.5 billion in bilateral credit facilities with banks which have various expirations dates between October 2015 and January 2017. The Registrants utilize their credit facilities to support their commercial paper programs, provide for other short-term borrowings and 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.



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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, PECO and BGE operate in rate-regulated environments in which the amount of new investment recovery may be delayed or limited and where such recovery takes place over an extended period of time. See Note 9 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further discussion of the Registrants' debt and credit agreements.

### ***Cash Flows from Operating Activities***

#### ***General***

Generation's cash flows from operating activities primarily result from the sale of electric energy and energy-related products and services to customers. Generation's future cash flows from operating activities may be affected by future demand for and market prices of energy and its ability to continue to produce and supply power at competitive costs as well as to obtain collections from customers.

ComEd's, PECO's and BGE's cash flows from operating activities primarily result from the transmission and distribution of electricity and, in the case of PECO and BGE, gas distribution services. ComEd's, PECO's and BGE's distribution services are provided to an established and diverse base of retail customers. ComEd's, PECO's and BGE's future cash flows may be affected by the economy, weather conditions, future legislative initiatives, future regulatory proceedings with respect to their rates or operations, competitive suppliers, and their ability to achieve operating cost reductions.

See Note 3 Regulatory Matters and Note 22 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements of the Exelon 2014 Form 10-K 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. On July 6, 2012, President Obama signed into law the Moving Ahead for Progress in the Twenty-first Century Act, which contains a pension funding provision that results in lower pension contributions in the near term while increasing the premiums pension plans pay to the Pension Benefit Guaranty Corporation. Certain provisions of the law were applied in 2012 while the others took effect in 2013. On August 8, 2014, this funding relief was extended for five years. The estimated impacts of the law are reflected in Exelon's projected pension contributions.

To the extent interest rates decline significantly or the pension plans do not earn the expected asset return rates, annual pension contribution requirements in future years could increase, especially in years 2018 and beyond. Additionally, expected contributions could change if Exelon changes its pension funding strategy.

#### ***Tax Matters***

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

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of March 31, 2015 may be as much as \$810 million, of which approximately \$310 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts will increase by a material amount.

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Exelon, Generation, and ComEd expect to receive tax refunds of approximately \$430 million, \$190 million, \$260 million, respectively, in 2015. PECO expects to make tax payments of approximately \$6 million related to IRS positions settling in 2015.

State and local governments continue to face increasing financial challenges, which may increase the risk of additional income tax levies, property taxes and other taxes or the imposition, extension or permanence of temporary tax levies.

The following table provides a summary of the major items affecting Exelon's cash flows from operations for the three months ended March 31, 2015 and 2014:

	Three Months Ended March 31,		Variance
	2015(c)	2014	
Net income	\$ 738	\$ 93	\$ 645
Add (subtract):			
Non-cash operating activities <sup>(a)</sup>	1,282	1,836	(554)
Pension and other postretirement benefit contributions	(269)	(472)	203
Income taxes	174	17	157
Changes in working capital and other noncurrent assets and liabilities <sup>(b)</sup>	(471)	(647)	176
Option premiums received, net	5	15	(10)
Counterparty collateral received (posted), net	31	(677)	708
<b>Net cash flows provided by operations</b>	<b>\$ 1,490</b>	<b>\$ 165</b>	<b>\$ 1,325</b>

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

(c) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.

Cash flows from operations for the three months ended March 31, 2015 and 2014 by Registrant were as follows:

	Three Months Ended March 31,	
	2015	2014
Exelon <sup>(a)</sup>	\$ 1,490	\$ 165
Generation <sup>(a)</sup>	837	(169)
ComEd	251	(9)
PECO	158	143
BGE	281	235

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.

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Changes in Exelon's, Generation's, ComEd's, PECO's and BGE's cash flows from operations were generally consistent with changes in each Registrant's respective results of operations, as adjusted by changes in working capital in the normal course of business, except as discussed below. In addition, significant operating cash flow impacts for the Registrants for the three months ended March 31, 2015 and 2014 were as follows:

*Generation*

Depending upon whether Generation is in a net mark-to-market liability or asset position, collateral may be required to be posted with or collected from its counterparties. In addition, the collateral posting and collection requirements differ depending on whether the transactions are on the exchange or in the OTC markets. During the three months ended March 31, 2015 and 2014, Generation had net collections/(payments) of counterparty collateral of \$62 million and \$(699) million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position. In addition, since the fourth quarter of 2014, the exchanges increased initial margin rates, which required Generation to post higher amounts of initial margin.

During the three months ended March 31, 2015 and 2014, Generation had net collections of approximately \$5 million and \$15 million, respectively, related to purchases and sales of options. The level of option activity in a given period may vary due to several factors, including changes in market conditions as well as changes in hedging strategy.

*ComEd*

As of March 31, 2015 and 2014, ComEd had a working capital deficit of \$139 million and \$399 million, respectively. The working capital deficit is primarily attributable to the increase in short-term borrowings and short-term debt due within one year. Cash flows from operating activities are sufficient to meet operating requirements; however, increased capital investment in infrastructure improvements and modernization pursuant to EIMA, transmission upgrades and expansions may require external debt financing or additional capital contributions from parent.

During the three months ended March 31, 2015 and 2014, ComEd's payables for Generation energy purchases increased/(decreased) by \$9 million and \$(4) million, respectively, and payables to other energy suppliers for energy purchases increased/(decreased) by \$(4) million and \$37 million, respectively.

*PECO*

During the three months ended March 31, 2015 and 2014, PECO's payables to Generation for energy purchases increased by \$7 million and \$4 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by \$23 million and \$39 million, respectively.

*BGE*

During the three months ended March 31, 2015 and 2014, BGE's payables to Generation for energy purchases increased/(decreased) by \$(14) million and \$14 million, respectively, and payables to other electric and gas suppliers for energy purchases increased by \$5 million and \$23 million, respectively.



**Table of Contents****Cash Flows from Investing Activities**

Cash flows used in investing activities for the three months ended March 31, 2015 and 2014 by Registrant were as follows:

	<b>Three Months Ended March 31,</b>	
	<b>2015</b>	<b>2014</b>
Exelon <sup>(a)</sup>	\$ (1,751)	\$ (1,011)
Generation <sup>(a)</sup>	(899)	(594)
ComEd	(523)	(330)
PECO	(144)	(182)
BGE	(132)	(187)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.

**Generation**

Generation has entered into several agreements to acquire equity interests in privately held and development stage entities which develop energy-related technologies. The agreements contain a series of scheduled investment commitments, including in-kind service contributions. There are approximately \$147 million of anticipated expenditures remaining through 2018 to fund anticipated planned capital and operating needs of the associated companies.

Generation has executed, or expects to execute, several construction and services contracts. The total estimated remaining expenditures for these projects are approximately \$1.8 billion and achievement of commercial operations is expected between 2015 and 2018 for all these projects.

Capital expenditures by Registrant for the three months ended March 31, 2015 and 2014 and projected amounts for the full year 2015 are as follows:

	<b>Projected Full Year 2015<sup>(e)</sup></b>	<b>Three Months Ended March 31,</b>	
		<b>2015</b>	<b>2014</b>
Exelon <sup>(a)</sup>	\$ 7,400	\$ 1,784	\$ 1,217
Generation <sup>(a)(b)</sup>	3,625	937	535
ComEd <sup>(c)</sup>	2,425	530	341
PECO	550	148	184
BGE	700	136	146
Other <sup>(d)</sup>	100	33	11

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, CENG is included on a fully consolidated basis in the 2015 results above.

(b) Includes nuclear fuel.

(c) The projected capital expenditures include approximately \$672 million of expected incremental spending pursuant to EIMA, ComEd has committed to invest approximately \$2.6 billion over a ten year period to modernize and storm-harden its distribution system and to implement smart grid technology.

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

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

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



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In 2014, Exelon and its affiliates initiated a comprehensive project to ensure corporate-wide compliance with Version 5 of the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection Standards (CIP V.5) which will become effective on April 1, 2016. Generation, ComEd, PECO and BGE will be incurring incremental capital expenditures in 2015 through 2016 associated with the CIP V.5 compliance implementation project.

### *Generation*

Approximately 34% and 6% of the projected 2015 capital expenditures at Generation are for the acquisition of nuclear fuel and investments in renewable energy and natural gas generation, respectively, with the remaining amounts reflecting additions and upgrades to existing facilities (including material condition improvements during nuclear refueling outages). Generation anticipates that they will fund capital expenditures with internally generated funds and borrowings.

### *ComEd, PECO and BGE*

Approximately 84%, 91% and 96% of the projected 2015 capital expenditures at ComEd, PECO and BGE, respectively, are for continuing projects to maintain and improve operations, including enhancing reliability and adding capacity to the transmission and distribution systems such as ComEd's reliability related investments required under EIMA, and ComEd's, PECO's and BGE's construction commitments under PJM's RTEP. In addition to the capital expenditure for continuing projects, ComEd's total expenditures include smart grid/smart meter technology required under EIMA and for PECO and BGE, total capital expenditures related to their respective smart meter program and SGIG project.

In 2010, NERC provided guidance to transmission owners that recommends ComEd, PECO and BGE perform assessments of all their transmission lines. In compliance with this guidance, ComEd, PECO and BGE submitted their final bi-annual reports to NERC in January 2014. ComEd, PECO and BGE will be incurring incremental capital expenditures associated with this guidance following the completion of the assessments. Specific projects and expenditures are identified as the assessments are completed. ComEd's, PECO's and BGE's forecasted 2015 capital expenditures above reflect capital spending in 2015 for remediation to be completed through 2017.

ComEd, PECO and BGE anticipate that they will fund their capital expenditures with internally generated funds and borrowings, including ComEd's capital expenditures associated with EIMA as further discussed in Note 5 Regulatory Matters of the Combined Notes to Consolidated Financial Statements.

**Table of Contents****Cash Flows from Financing Activities**

Cash flows provided by (used in) financing activities for the three months ended March 31, 2015 and 2014 by Registrant were as follows:

	Three Months Ended March 31,	
	2015	2014
Exelon <sup>(a)</sup>	\$ 208	\$ 151
Generation <sup>(a)</sup>	(186)	71
ComEd	314	344
PECO	(6)	(80)
BGE	(172)	(56)

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.

*Debt*

See Note 9 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for further details of the Registrants' debt issuances and retirements.

*Dividends*

Cash dividend payments and distributions during the three months ended March 31, 2015 and 2014 by Registrant were as follows:

	Three Months Ended March 31,	
	2015	2014
Exelon <sup>(a)</sup>	\$ 269	\$ 266
Generation <sup>(a)</sup>	1,356	30
ComEd	75	76
PECO	70	80
BGE <sup>(b)</sup>	39	3

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, the 2015 activity includes CENG on a fully consolidated basis.

(b) Includes dividends paid on BGE's preference stock.

*First Quarter 2015 Dividend*

On January 27, 2015, the Exelon Board of Directors declared a first quarter 2015 regular quarterly dividend of \$0.31 per share on Exelon's common stock payable on March 10, 2015, to shareholders of record of Exelon at the end of the day on February 13, 2015.

*Second Quarter 2015 Dividend*

On April 28, 2015, the Exelon Board of Directors declared a second quarter 2015 regular quarterly dividend of \$0.31 per share on Exelon's common stock payable on June 10, 2015, to shareholders of record of Exelon at the end of the day on May 15, 2015.

*Short-Term Borrowings*

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During the three months ended March 31, 2015, ComEd and BGE repaid \$21 million and \$120 million of commercial paper, respectively, and Generation repaid \$1 million in short-term notes payable. During the three

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months ended March 31, 2014, Generation and ComEd issued \$352 million and \$350 million of commercial paper, respectively. Further, BGE repaid \$66 million of commercial paper and Generation issued \$3 million in short-term notes payable during the three months ended March 31, 2014.

*Contributions from Parent/Member*

During the three months ended March 31, 2015 and 2014, ComEd received \$14 million and \$38 million from Parent (Exelon), respectively.

*Other*

For the three months ended March 31, 2015, other financing activities primarily consists debt issuance costs. See Note 9 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information.

**Credit Matters**

The Registrants fund liquidity needs for capital investment, working capital, energy hedging and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets and large, diversified credit facilities. The credit facilities include \$8.5 billion in aggregate total commitments of which \$6.5 billion was available as of March 31, 2015, and of which no financial institution has more than 8% of the aggregate commitments. Exelon, Generation, ComEd, PECO and BGE had access to the commercial paper market during the first quarter of 2015 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 of Exelon's 2014 Form 10-K for further information regarding the effects of uncertainty in the capital and credit markets.

The Registrants believe their cash flow from operating activities, access to credit markets and their credit facilities provide sufficient liquidity. If Generation lost its investment grade credit rating as of March 31, 2015, it would have been required to provide incremental collateral of \$2.3 billion to meet 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, which is well within its current available credit facility capacities of \$4.1 billion. If ComEd lost its investment grade credit rating as of March 31, 2015, it would have been required to provide incremental collateral of \$15 million, which is well within its current available credit facility capacity of \$715 million, which takes into account commercial paper borrowings as of March 31, 2015. If PECO lost its investment grade credit rating as of March 31, 2015, it would not be required to provide collateral pursuant to PJM's credit policy and would have been required to provide collateral of \$36 million related to its natural gas procurement contracts, which, in the aggregate, are well within PECO's current available credit facility capacity of \$599 million. If BGE lost its investment grade credit rating as of March 31, 2015, it would have been required to provide collateral of \$2 million pursuant to PJM's credit policy and would have been required to provide collateral of \$111 million related to its natural gas procurement contracts, which, in the aggregate, are well within BGE's current available credit facility capacity of \$600 million.

*Exelon Credit Facilities*

Exelon, ComEd and BGE meet their short-term liquidity requirements primarily through the issuance of commercial paper. Generation and PECO meet their short-term liquidity requirements primarily through the issuance of commercial paper and borrowings from the intercompany money pool. The Registrants may use their respective credit facilities for general corporate purposes, including meeting short-term funding requirements and

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the issuance of letters of credit. See Note 9 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at March 31, 2015:

**Commercial Paper Programs**

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at March 31, 2015	Average Interest Rate on Commercial Paper Borrowings for the three months ended March 31, 2015
Exelon Corporate	\$ 500	\$	%
Generation	5,600		%
ComEd	1,000	283	0.51%
PECO	600		%
BGE	600		0.45%

In order to maintain their respective commercial paper programs in the amounts indicated above, each Registrant must have 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.

**Credit Agreements**

Borrower	Facility Type	Aggregate Bank Commitment(a)	Facility Draws	Outstanding Letters of Credit(b)	Actual	Available Capacity at March 31, 2015 To Support Additional Commercial Paper(c)
Exelon Corporate	Syndicated Revolver	\$ 500	\$	\$ 26	\$ 474	\$ 474
Generation	Syndicated Revolver	5,300		1,240	4,060	4,060
Generation	Bilaterals	500		380	120	36
ComEd	Syndicated Revolver	1,000		2	998	715
PECO	Syndicated Revolver	600		1	599	599
BGE	Syndicated Revolver	600			600	600

(a) Excludes \$123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expire on October 16, 2015. These facilities are solely utilized to issue letters of credit. See Note 9 Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information.

(b) Excludes nonrecourse debt letters of credit, see Note 13 Debt and Credit Agreements in the Exelon 2014 Form 10-K for further information on Continental Wind nonrecourse debt.

(c) Excludes \$200 million bilateral credit facilities that do not back Generation's commercial paper program.

As of March 31, 2015, there were no borrowings under the Registrants' credit facilities.

Borrowings under Exelon Corporate's, Generation's, ComEd's, PECO's and BGE's credit facilities bear interest at a rate based upon either the prime rate or a LIBOR-based rate, plus an adder based upon each Registrant's credit rating. Exelon Corporate, Generation, ComEd, PECO and BGE have adders of 27.5, 27.5, 7.5, 0.0 and 0.0 basis points, respectively, for prime based borrowings and 127.5, 127.5, 107.5, 90.0 and 100.0 basis points, respectively, for LIBOR-based borrowings. The maximum adders for prime rate borrowings and LIBOR-





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based rate borrowings are 65 basis points and 165 basis points, respectively. The credit agreements also require the borrower to pay a facility fee based upon the aggregate commitments under the agreement. The fee varies depending upon the respective credit ratings of the borrower.

Each revolving credit agreement for Exelon, Generation, ComEd, PECO and BGE 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 following table summarizes the minimum thresholds reflected in the credit agreements for the three months ended March 31, 2015:

	Exelon	Generation	ComEd	PECO	BGE
Credit agreement threshold	2.50 to 1	3.00 to 1	2.00 to 1	2.00 to 1	2.00 to 1

At March 31, 2015, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	8.09	11.81	7.23	9.28	9.88

An event of default under any Registrant's indebtedness will 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 will constitute an event of default under the Exelon Corporate credit facility.

**Security Ratings**

The Registrants' access to the capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on the securities ratings of the entity that is accessing the capital markets.

The Registrants' borrowings are not subject to default or prepayment as a result of a downgrading of securities, although such a downgrading of a Registrant's securities could increase fees and interest charges under that Registrant's credit agreements.

As part of the normal course of business, the Registrants enter into contracts that contain express provisions or otherwise permit the Registrants and their counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable contracts law, if the Registrants are downgraded by a credit rating agency, 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, which could include the posting of collateral. See *Credit Matters* above and Note 8 *Derivative Financial Instruments* of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

**Table of Contents****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. Maximum amounts contributed to and borrowed from the money pool by participant and the net contribution or borrowing as of March 31, 2015, are presented in the following table:

Participant	Three Months Ended March 31, 2015		As of March 31, 2015
	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	\$	\$ 1,709	\$ (936)
PECO		80	(65)
BSC		413	(321)
Exelon Corporate	2,008	N/A	1,322

**Investments in Nuclear Decommissioning Trust Funds**

Exelon Generation and CENG maintain trust funds, as required by the NRC, to fund certain costs of decommissioning nuclear plants. The mix of securities in the trust funds is designed to provide returns to be used to fund decommissioning and to offset inflationary increases in decommissioning costs. Generation actively monitors the investment performance of the trust funds and periodically reviews asset allocations in accordance with Generation's NDT fund investment policy. Generation's and CENG's investment policies establish limits on the concentration of holdings in any one company and also in any one industry. See Note 11 Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for further information regarding the trust funds, the NRC's minimum funding requirements and related liquidity ramifications.

**Shelf Registration Statements**

The Registrants have a currently effective combined shelf registration statement unlimited in amount, filed with the SEC, that will expire in May 2017. The ability of each Registrant to sell securities off the 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**

As of March 31, 2015, ComEd had \$442 million available in long-term debt refinancing authority and \$803 million available in new money long-term debt financing authority from the ICC. As of March 31, 2015, PECO had \$1.1 billion available in long-term debt financing authority from the PAPUC. As of March 31, 2015, BGE had \$1.4 billion available in long-term financing authority from MDPSC.

As of March 31, 2015, ComEd, PECO and BGE had short-term financing authority from FERC, which expires on December 31, 2015, of \$2.5 billion, \$2.5 billion, and \$700 million, respectively. Generation currently has blanket financing authority from FERC, which was granted in connection with its market-based rate authority.

**Contractual Obligations and Off-Balance Sheet Arrangements**

Contractual obligations represent cash obligations that are considered to be firm commitments and commercial commitments triggered by future events. See Note 17 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

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Generation, ComEd, PECO and BGE have obligations related to contracts for the purchase of power and fuel supplies, and ComEd, PECO and BGE have obligations related to their financing trusts. The power and fuel purchase contracts and the financing trusts have been considered for consolidation in the Registrants' respective financial statements pursuant to the authoritative guidance for VIEs. See Note 1 Basis of Presentation of the Combined Notes to Consolidated Financial Statements for further information.

For an in-depth discussion of the Registrant's contractual obligations and off-balance sheet arrangements, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Contractual Obligations and Off-Balance Sheet Arrangements in the Exelon 2014 Form 10-K.

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**Item 3. 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 executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. The following discussion serves as an update to ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK of the Registrants' 2014 Annual Report on Form 10-K incorporated herein by reference.

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

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

**Generation**

**Normal Operations and Hedging Activities.** Electricity available from Generation's owned or contracted generation supply in excess of Generation's obligations to customers, including portions of ComEd's, PECO's and BGE's retail load, is sold into the wholesale markets. To reduce price risk caused by market fluctuations, Generation enters into non-derivative contracts as well as 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 will occur during 2015 through 2017.

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. Exelon's hedging program involves the hedging of commodity risk for Exelon's expected generation, typically on a ratable basis over a three-year period. As of March 31, 2015, the proportion of expected generation hedged is 94%-97%, 67%-70% and 37%-40% for 2015, 2016 and 2017, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation is the volume of energy that best represents our commodity position in energy markets from owned or contracted for capacity based upon a simulated dispatch model that makes assumptions regarding future market conditions, which are calibrated to market quotes for power, fuel, load following products, and options. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including Generation's sales to ComEd, PECO and BGE to serve their retail load. See Note 4 Mergers, Acquisitions, and Dispositions of the combined Notes to Consolidated Financial Statement for more detail regarding divestitures.

A portion of Generation's hedging strategy may be accomplished with fuel products based on assumed correlations between power and fuel prices, which routinely change in the market. Market price risk exposure is the risk of a change in the value of unhedged positions. The forecasted market price risk exposure for Generation's entire non-proprietary trading portfolio associated with a \$5 reduction in the annual average around-the-clock energy price based on March 31, 2015 market conditions and hedged position would be an \$10 million increase in pre-tax net income for 2015 and a decrease in pre-tax net income of approximately \$280 million and \$630 million, respectively, for 2016 and 2017. 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.

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**Proprietary Trading Activities.** Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon's RMC. The proprietary trading portfolio is subject to a risk management policy that includes stringent risk management limits, including volume, stop loss and Value-at-Risk (VaR) limits to manage exposure to market risk. Additionally, the Exelon risk management group and Exelon's RMC monitor the financial risks of the proprietary trading activities. The proprietary trading activities, which included physical volumes of 1,808 GWhs and 2,494 GWhs for the three months ended March 31, 2015 and 2014, respectively, are a complement to Generation's energy marketing portfolio, but represent a small portion of Generation's overall revenue from energy marketing activities. Proprietary trading portfolio activity for the three months ended March 31, 2015 resulted in pre-tax gains of \$4 million due to net mark-to-market gains of \$3 million and realized gains of \$1 million. Generation uses a 95% confidence interval, assuming standard normal distribution, one day holding period, and a one-tailed statistical measure in calculating its VaR. The daily VaR on proprietary trading activity averaged \$0.3 million of exposure during the quarter. Generation has not segregated proprietary trading activity within the following discussion because of the relative size of the proprietary trading portfolio in comparison to Generation's total revenues net of purchased power and fuel expense from continuing operations for the three months ended March 31, 2015 of \$2,407 million.

**Fuel Procurement.** Generation procures oil and natural gas through long-term and short-term contracts and spot-market purchases. Nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services, coal, oil and natural gas are subject to price fluctuations and availability restrictions. Supply market conditions may make Generation's procurement contracts subject to credit risk related to the potential non-performance of counterparties to deliver the contracted commodity or service at the contracted prices. Approximately 50% of Generation's uranium concentrate requirements from 2015 through 2019 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. See Note 17 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for additional information regarding uranium and coal supply agreement matters.

**ComEd**

ComEd entered into 20-year contracts for renewable energy and RECs beginning in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The annual commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms. Pursuant to the ICC's Order on December 19, 2012, ComEd's commitments under the existing long-term contracts were reduced for the June 2013 through May 2014 procurement period. In addition, the ICC's December 18, 2013 Order approved the reduction of ComEd's commitments under those contracts for the June 2014 through May 2015 procurement period, and the amount of the reduction was approved by the ICC in March 2014. See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information regarding energy procurement and derivatives.

**PECO**

PECO has contracts to procure electric supply that were executed through the competitive procurement process outlined in its PAPUC-approved DSP Programs, which are further discussed in Note 5 Regulatory Matters of the Combined Notes to the Consolidated Financial Statements. PECO has certain full requirements

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contracts and block contracts which are considered derivatives and qualify for the normal purchases and normal sales scope exception under current derivative authoritative guidance, and as a result are accounted for on an accrual basis of accounting. Under the DSP Programs, PECO is permitted to recover its electric supply procurement costs from retail customers with no mark-up.

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

PECO does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

***BGE***

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

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

BGE does not enter into derivatives for speculative or proprietary trading purposes. For additional information on these contracts, see Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements.

***Trading and Non-Trading Marketing Activities.*** The following detailed presentation of Exelon's, Generation's and ComEd'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 and ComEd's commodity mark-to-market net asset or liability balance sheet position from December 31, 2014 to March 31, 2015. It indicates the drivers behind changes in the balance sheet amounts. This table incorporates the mark-to-market activities that are immediately recorded in earnings as well as the settlements from OCI to earnings and changes in fair value for the cash flow hedging activities that are recorded in accumulated OCI on the Consolidated Balance Sheets. This table excludes all normal purchase and normal sales contracts and does not segregate proprietary trading activity. See Note 8 Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for additional information on the balance sheet classification of the mark-to-market energy contract net assets (liabilities) recorded as of March 31, 2015 and December 31, 2014.

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	Generation	ComEd	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2014 <sup>(a)</sup>	\$ 1,712	\$ (207)	\$ 1,505
Total change in fair value during 2015 of contracts recorded in results of operations	85		85
Reclassification to realized at settlement of contracts recorded in results of operations	69		69
Reclassification to realized at settlement from accumulated OCI	(2)		(2)
Changes in fair value energy derivative <sup>(b)</sup>		(34)	(34)
Changes in allocated collateral	(60)		(60)
Changes in net option premium paid/(received)	(5)		(5)
Option premium amortization	(9)		(9)
Other balance sheet reclassifications	3		3
Total mark-to-market energy contract net assets (liabilities) at March 31, 2015 <sup>(a)</sup>	\$ 1,793	\$ (241)	\$ 1,552

(a) Amounts are shown net of cash collateral paid to and received from counterparties.

(b) For ComEd, the changes in fair value are recorded as a change in regulatory assets or liabilities. As of March 31, 2015, ComEd recorded a \$241 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. For the three months ended March 31, 2015, ComEd also recorded \$36 million of decreases in fair value and \$2 million of realized gains due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Fair Values.** The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 7 Fair Value of Financial Assets and Liabilities of the Combined Notes to Consolidated Financial Statements for additional information regarding fair value measurements and the fair value hierarchy.

**Exelon**

	Maturities Within					2020 and Beyond	Total Fair Value
	2015	2016	2017	2018	2019		
Normal Operations, Commodity derivative contracts <sup>(a)(b)</sup>							
Actively quoted prices (Level 1)	\$ (144)	\$ (11)	\$ 10	\$ (17)	\$ (14)	\$ (9)	\$ (185)
Prices provided by external sources (Level 2)	526	330	39	8		8	911
Prices based on model or other valuation methods (Level 3) <sup>(c)</sup>	419	332	196	5	(6)	(120)	826
Total	\$ 801	\$ 651	\$ 245	\$ (4)	\$ (20)	\$ (121)	\$ 1,552

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in results of operations.

(b) Amounts are shown net of cash collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$1,346 million at March 31, 2015.

(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Table of Contents****Generation**

	Maturities Within					2020 and Beyond	Total Fair Value
	2015	2016	2017	2018	2019		
Normal Operations, Commodity derivative contracts <sup>(a)(b)</sup>							
Actively quoted prices (Level 1)	\$ (144)	\$ (11)	\$ 10	\$ (17)	\$ (14)	\$ (9)	\$ (185)
Prices provided by external sources (Level 2)	526	330	39	8		8	911
Prices based on model or other valuation methods (Level 3)	435	351	214	22	12	33	1,067
<b>Total</b>	<b>\$ 817</b>	<b>\$ 670</b>	<b>\$ 263</b>	<b>\$ 13</b>	<b>\$ (2)</b>	<b>\$ 32</b>	<b>\$ 1,793</b>

(a) Mark-to-market gains and losses on other economic hedge and trading derivative contracts that are recorded in the results of operations.

(b) Amounts are shown net of cash collateral paid to and received from counterparties (and offset against mark-to-market assets and liabilities) of \$1,346 million at March 31, 2015.

**ComEd**

	Maturities Within					2020 and Beyond	Total Fair Value
	2015	2016	2017	2018	2019		
Prices based on model or other valuation methods <sup>(a)</sup> (Level 3)	\$ (16)	\$ (19)	\$ (18)	\$ (17)	\$ (18)	\$ (153)	\$ (241)

(a) Represents ComEd's net liabilities associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

**Credit Risk, Collateral, and Contingent Related Features (Exelon, Generation, ComEd, PECO and BGE)**

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. See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.



**Table of Contents****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 March 31, 2015. 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 exclude credit risk exposure from individual retail customers, uranium procurement contracts, and exposure through RTOs, ISOs, NYMEX, ICE and Nodal commodity exchanges, which are discussed below. Additionally, the figures in the tables below exclude exposures with affiliates, including net receivables with ComEd, PECO and BGE of \$52 million, \$36 million and \$26 million, respectively. See Note 25 Related Party Transactions of the Exelon 2014 Form 10-K for additional information.

Rating as of March 31, 2015	Total Exposure Before		Credit Collateral(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure			
	Credit	Collateral							
Investment grade	\$	1,570	\$	56	\$	1,514	1	\$	442
Non-investment grade		63		16		47			
No external ratings									
Internally rated investment grade		495				495			
Internally rated non-investment grade		68		3		65			
Total	\$	2,196	\$	75	\$	2,121	1	\$	442

Rating as of March 31, 2015	Maturity of Credit Risk Exposure			Total Exposure Before Credit Collateral					
	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years						
Investment grade	\$	1,105	\$	430	\$	35	\$	1,570	
Non-investment grade		34		24		5		63	
No external ratings									
Internally rated investment grade		392		97		6		495	
Internally rated non-investment grade		68						68	
Total		\$	1,599	\$	551	\$	46	\$	2,196

Net Credit Exposure by Type of Counterparty	As of March 31, 2015	
Financial institutions	\$	324
Investor-owned utilities, marketers, power producers		897
Energy cooperatives and municipalities		869
Other		31
Total	\$	2,121

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- (a) As of March 31, 2015, credit collateral held from counterparties where Generation had credit exposure included \$62 million of cash and \$14 million of letters of credit.

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***ComEd***

There have been no significant changes or additions to ComEd's exposures to credit risk that are described in ITEM 1A. RISK FACTORS of Exelon's 2014 Annual Report on Form 10-K.

See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

***PECO***

There have been no significant changes or additions to PECO's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2014 Annual Report on Form 10-K.

See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

***BGE***

There have been no significant changes or additions to BGE's exposures to credit risk as described in ITEM 1A. RISK FACTORS of Exelon's 2014 Annual Report on Form 10-K.

See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding credit exposure to suppliers.

***Collateral (Exelon, Generation, ComEd, PECO and BGE)***

***Generation***

As part of the normal course of business, Generation routinely enters into physical or financial contracts for the sale and purchase of electricity, fossil fuel and other commodities. These contracts either contain express provisions or otherwise permit Generation and its counterparties to demand adequate assurance of future performance when there are reasonable grounds for doing so. In accordance with the contracts and applicable law, if Generation is downgraded by a credit rating agency, especially if such downgrade is to a level below investment grade, it is possible that a counterparty would attempt to rely on such a downgrade as a basis for making a demand for adequate assurance of future performance. Depending on Generation's net position with a counterparty, the demand could be for the posting of collateral. In the absence of expressly agreed-to provisions that specify the collateral that must be provided, collateral requested will be a function of the facts and circumstances of the situation at the time of the demand. In this case, Generation believes an amount of several months of future payments (i.e. capacity payments) rather than a calculation of fair value is the best estimate for the contingent collateral obligation, which has been factored into the disclosure below. See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for information regarding collateral requirements.

Generation transacts 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. See Note 9 Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of March 31, 2015, Generation had cash collateral of \$1,428 million posted and cash collateral held of \$69 million for counterparties with derivative positions, of which \$1,346 million and \$8 million in net cash

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collateral posted were offset against commodity mark-to-market and interest rate and foreign exchange derivative assets and liabilities related to underlying commodity contracts, respectively. As of March 31, 2015, \$5 million of cash collateral posted was not offset against net derivative positions because it was not associated with commodity-related derivatives, were associated with accrual positions, or as of the balance sheet date there were no positions to offset. See Note 17 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for information regarding the letters of credit supporting the cash collateral.

*ComEd*

As of March 31, 2015, ComEd held approximately \$2 million 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 Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements in this report and Note 3 Regulatory Matters of the 2014 Exelon Form 10-K for additional information.

*PECO*

As of March 31, 2015, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

*BGE*

BGE is not required to post collateral under its electric supply contracts. As of March 31, 2015, BGE was not required to post collateral under its natural gas procurement contracts. See Note 8 Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information.

***RTOs and ISOs (Exelon, Generation, ComEd, PECO and BGE)***

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

***Exchange Traded Transactions (Exelon and Generation)***

Generation enters into commodity transactions on NYMEX, ICE and the Nodal exchange. The NYMEX, ICE and Nodal exchange clearinghouses act as the counterparty to each trade. Transactions on the NYMEX, ICE and Nodal exchange must adhere to comprehensive collateral and margining requirements. As a result, transactions on NYMEX, ICE and Nodal exchange are significantly collateralized and have limited counterparty credit risk. Since the fourth quarter of 2014, the exchanges increased initial marginal rates, which required Generation to post higher amounts of initial margin collateral. Generation believes that increased market volatility and extreme weather events, such as the Polar Vortex, contributed to the rate increases.

***Long-Term Leases (Exelon)***

Exelon's Consolidated Balance Sheet, as of March 31, 2015, included a \$365 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of

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leased assets at the end of the respective lease terms of \$685 million, less unearned income of \$320 million. As of December 31, 2014, Exelon's Consolidated Balance sheet included a \$361 million net investment in coal-fired plants in Georgia subject to long-term leases, which represented the estimated residual value of leased assets at the end of the respective lease terms of \$685 million, less unearned income of \$324 million. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessee does not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessee to arrange for a third party to bid on a service contract for a period following the lease term. Exelon will be subject to residual value risk if the lessee does not exercise the fixed purchase options. This risk is partially mitigated by the fair value of the scheduled payments under the service contract. However, such payments are not guaranteed. Further, the term of the service contract 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. Management regularly evaluates the creditworthiness of Exelon's counterparties to these long-term leases. Exelon monitors the continuing credit quality of the credit enhancement party.

**Interest Rate and Foreign Exchange Risk (Exelon, Generation, ComEd, PECO and BGE)**

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 rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At March 31, 2015, Exelon had \$900 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had \$3,068 million and \$768 million of notional amounts of floating-to-fixed hedges outstanding, respectively. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in approximately a \$1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 2015. To manage foreign exchange rate exposure associated with international energy purchases in currencies other than U.S. dollars, Generation utilizes foreign currency derivatives, which are typically designated as economic hedges.

**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 March 31, 2015, 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 \$629 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 2. 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.

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**Item 4. Controls and Procedures**

During the first quarter of 2015, each Registrant's management, including its principal executive officer and principal financial officer, evaluated the effectiveness of that Registrant's disclosure controls and procedures related to the recording, processing, summarizing and reporting of information in its 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.

Consistent with guidance issued by the Securities and Exchange Commission that an assessment of internal controls over financial reporting of a recently acquired business may be omitted from management's evaluation of disclosure controls and procedures, management is excluding an assessment of such internal controls of Integrys, which was acquired on November 1, 2014, from its evaluation of the effectiveness of Exelon's and Generation's disclosure controls and procedures. The total assets related to Integrys are approximately 0.74% and 1.43%, respectively, and total revenues related to Integrys are 8.24% and 12.46%, respectively, of Exelon's and Generation's related consolidated financial statement amounts as of and for the three months ended March 31, 2015.

Accordingly, as of March 31, 2015, the principal executive officer and principal financial officer of each Registrant concluded that such Registrant's disclosure controls and procedures were effective to accomplish its objectives. All Registrants continually strive 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. There have been no changes in internal control over financial reporting that occurred during the first quarter of 2015 that have materially affected, or are reasonably likely to materially affect, any of the Registrant's internal control over financial reporting.

**Table of Contents****PART II OTHER INFORMATION****Item 1 Legal Proceedings**

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 (a) ITEM 3. LEGAL PROCEEDINGS of Exelon's 2014 Form 10-K and (b) Note 5 Regulatory Matters and Note 17 Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements in PART I, ITEM 1. FINANCIAL STATEMENTS of this Report. Such descriptions are incorporated herein by these references.

**Item 1A Risk Factors  
Risks Related to Exelon**

At March 31, 2015, the Registrant's risk factors were consistent with the risk factors described in Exelon's 2014 Form 10-K.

**Item 4 Mine Safety Disclosures  
Exelon, Generation, ComEd, PECO and BGE**

Not applicable to the Registrants.

**Item 6 Exhibits**

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**

<b>No.</b>	<b>Description</b>
4.1	Supplemental Indenture dated as of February 18, 2015 from ComEd to BNY Mellon Trust Company of Illinois, as trustee, and D.G. Donovan, as co-trustee (file no. 1-1839, Form 8-K dated March 2, 2015, Exhibit 4.1).
101.INS	XBRL Instance
101.SCH	XBRL Taxonomy Extension Schema
101.CAL	XBRL Taxonomy Extension Calculation
101.DEF	XBRL Taxonomy Extension Definition
101.LAB	XBRL Taxonomy Extension Labels
101.PRE	XBRL Taxonomy Extension Presentation

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Certifications Pursuant to Rule 13a-14(a) and 15d-14(a) of the Securities and Exchange Act of 1934 as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015 filed by the following officers for the following companies:

- 31-1 Filed by Christopher M. Crane for Exelon Corporation
- 31-2 Filed by Jonathan W. Thayer for Exelon Corporation
- 31-3 Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
- 31-4 Filed by Bryan P. Wright for Exelon Generation Company, LLC
- 31-5 Filed by Anne R. Pramaggiore for Commonwealth Edison Company
- 31-6 Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
- 31-7 Filed by Craig L. Adams for PECO Energy Company
- 31-8 Filed by Phillip S. Barnett for PECO Energy Company
- 31-9 Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
- 31-10 Filed by David M. Vahos for Baltimore Gas and Electric Company

Certifications Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code (Sarbanes Oxley Act of 2002) as to the Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2015 filed by the following officers for the following companies:

- 32-1 Filed by Christopher M. Crane for Exelon Corporation
- 32-2 Filed by Jonathan W. Thayer for Exelon Corporation
- 32-3 Filed by Kenneth W. Cornew for Exelon Generation Company, LLC
- 32-4 Filed by Bryan P. Wright for Exelon Generation Company, LLC
- 32-5 Filed by Anne R. Pramaggiore for Commonwealth Edison Company
- 32-6 Filed by Joseph R. Trpik, Jr. for Commonwealth Edison Company
- 32-7 Filed by Craig L. Adams for PECO Energy Company
- 32-8 Filed by Phillip S. Barnett for PECO Energy Company
- 32-9 Filed by Calvin G. Butler, Jr. for Baltimore Gas and Electric Company
- 32-10 Filed by David M. Vahos for Baltimore Gas and Electric Company



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**SIGNATURES**

Pursuant to requirements 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.

**EXELON CORPORATION**

/s/ CHRISTOPHER M. CRANE  
Christopher M. Crane  
President and Chief Executive Officer

(Principal Executive Officer) and Director

/s/ DUANE M. DESPARTE  
Duane M. DesParte  
Senior Vice President and Corporate Controller

(Principal Accounting Officer)

April 29, 2015

/s/ JONATHAN W. THAYER  
Jonathan W. Thayer  
Senior Executive Vice President and Chief Financial  
Officer

(Principal Financial Officer)

Pursuant to requirements 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.

**EXELON GENERATION COMPANY, LLC**

/s/ KENNETH W. CORNEW  
Kenneth W. Cornew  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ ROBERT M. AIKEN  
Robert M. Aiken  
Chief Accounting Officer  
(Principal Accounting Officer)

April 29, 2015

/s/ BRYAN P. WRIGHT  
Bryan P. Wright  
Senior Vice President and Chief Financial Officer

(Principal Financial Officer)

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Pursuant to requirements 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.

**COMMONWEALTH EDISON COMPANY**

/s/ ANNE R. PRAMAGGIORE  
Anne R. Pramaggiore  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ GERALD J. KOZEL  
Gerald J. Kozel  
Vice President and Controller

(Principal Accounting Officer)

April 29, 2015

/s/ JOSEPH R. TRPIK, JR.  
Joseph R. Trpik, Jr.  
Senior Vice President, Chief Financial Officer and  
Treasurer

(Principal Financial Officer)

Pursuant to requirements 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.

**PECO ENERGY COMPANY**

/s/ CRAIG L. ADAMS  
Craig L. Adams  
President and Chief Executive Officer

(Principal Executive Officer)

/s/ SCOTT A. BAILEY  
Scott A. Bailey  
Vice President and Controller

(Principal Accounting Officer)

April 29, 2015

/s/ PHILLIP S. BARNETT  
Phillip S. Barnett  
Senior Vice President, Chief Financial Officer and  
Treasurer

(Principal Financial Officer)

Pursuant to requirements 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.

**BALTIMORE GAS AND ELECTRIC COMPANY**

/s/ CALVIN G. BUTLER, JR.  
Calvin G. Butler, Jr.  
Chief Executive Officer

(Principal Executive Officer)

/s/ DAVID M. VAHOS  
David M. Vahos

Vice President, Chief Financial Officer and Treasurer  
(Principal Financial Officer)

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/s/ MATTHEW N. BAUER  
Matthew N. Bauer  
Vice President and Controller

(Principal Accounting Officer)

April 29, 2015