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

FORM 10-Q

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

For the Quarterly Period Ended September 30, 2015

or

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

Commission File Number	Name of Registrant; State of Incorporation; Address of Principal Executive Offices; and Telephone Number	IRS Employer Identification Number
1-16169	EXELON CORPORATION (a Pennsylvania corporation) 10 South Dearborn Street P.O. Box 805379 Chicago, Illinois 60680-5379 (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 Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

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	☒			
Exelon Generation Company, LLC			☒	
Commonwealth Edison Company			☒	
PECO Energy Company			☒	
Baltimore Gas and Electric Company			☒	

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 September 30, 2015 was:

Exelon Corporation Common Stock, without par value	919,564,380
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,973
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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GLOSSARY OF TERMS AND ABBREVIATIONS

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

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

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

GLOSSARY OF TERMS AND ABBREVIATIONS

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

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 1, 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 19; 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 and the Registrants' websites at www.exeloncorp.com. Information contained on the Registrants' websites shall not be deemed incorporated into, or to be a part of, this Report.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions, except per share data)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenues	$ 7,401	$ 6,912	$22,746	$20,173
Operating expenses				
Purchased power and fuel	3,291	2,591	10,210	8,943
Purchased power and fuel from affiliates	—	57	—	456
Operating and maintenance	1,996	1,982	6,119	6,005
Depreciation and amortization	606	577	1,818	1,732
Taxes other than income	310	306	908	887
Total operating expenses	6,203	5,513	19,055	18,023
Equity in losses of unconsolidated affiliates	—	—	—	(20)
Gain on sales of assets	2	339	10	356
Gain on consolidation and acquisition of businesses	—	—	—	261
Operating income	1,200	1,738	3,701	2,747
Other income and (deductions)				
Interest expense, net	(243)	(247)	(724)	(691)
Interest expense to affiliates	(10)	(11)	(31)	(31)
Other, net	(244)	16	(179)	346
Total other income and (deductions)	(497)	(242)	(934)	(376)
Income before income taxes	703	1,496	2,767	2,371
Income taxes	115	422	805	646
Equity in losses of unconsolidated affiliates	(1)	—	(3)	—
Net income	587	1,074	1,959	1,725
Net income (loss) attributable to noncontrolling interest and preference stock dividends	(42)	81	—	121
Net income attributable to common shareholders	$ 629	$ 993	$ 1,959	$ 1,604
Comprehensive income, net of income taxes				
Net income	$ 587	$ 1,074	$ 1,959	$ 1,725
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(11)	(11)	(35)	(18)
Actuarial loss reclassified to periodic cost	55	38	165	109
Pension and non-pension postretirement benefit plans valuation adjustment	—	(8)	(29)	240
Unrealized gain (loss) on cash flow hedges	(3)	(19)	4	(92)
Unrealized gain (loss) on equity investments	—	(3)	—	8
Unrealized gain (loss) on foreign currency translation	(8)	(5)	(17)	(6)
Unrealized loss on marketable securities	(1)	(3)	—	(2)
Reversal of CENG equity method AOCI	—	—	—	(116)
Other comprehensive income (loss)	32	(11)	88	123
Comprehensive income	$ 619	$ 1,063	$ 2,047	$ 1,848
Average shares of common stock outstanding:				
Basic	913	861	879	860
Diluted	915	863	883	863
Earnings per average common share:				
Basic	$ 0.69	$ 1.15	$ 2.23	$ 1.87
Diluted	$ 0.69	$ 1.15	$ 2.22	$ 1.86
Dividends per common share	$ 0.31	$ 0.31	$ 0.93	$ 0.93

Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities		
Net income	$ 1,959	$ 1,725
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	2,930	2,856
Impairment of long-lived assets	25	162
Gain on consolidation and acquisition of businesses	—	(268)
Gain on sales of assets	(10)	(356)
Deferred income taxes and amortization of investment tax credits	241	459
Net fair value changes related to derivatives	(363)	522
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	221	(141)
Other non-cash operating activities	856	698
Changes in assets and liabilities:		
Accounts receivable	175	198
Inventories	65	(316)
Accounts payable, accrued expenses and other current liabilities	(147)	(322)
Option premiums received, net	27	21
Counterparty collateral received (posted), net	305	(615)
Income taxes	300	72
Pension and non-pension postretirement benefit contributions	(430)	(516)
Other assets and liabilities	(480)	(536)
Net cash flows provided by operating activities	5,674	3,643
Cash flows from investing activities		
Capital expenditures	(5,443)	(4,114)
Proceeds from nuclear decommissioning trust fund sales	4,551	5,464
Investment in nuclear decommissioning trust funds	(4,737)	(5,550)
Acquisition of businesses	(28)	(67)
Proceeds from sale of long-lived assets	145	660
Proceeds from termination of direct financing lease investment	—	335
Proceeds from sales of investments	—	7
Cash and restricted cash acquired from consolidations and acquisitions	—	129
Change in restricted cash	(70)	(151)
Other investing activities	(107)	(89)
Net cash flows used in investing activities	(5,689)	(3,376)
Cash flows from financing activities		
Changes in short-term borrowings	230	236
Issuance of long-term debt	5,909	3,212
Retirement of long-term debt	(1,745)	(1,214)
Issuance of common stock	1,868	—
Distributions to noncontrolling interest of consolidated VIE	—	(415)
Dividends paid on common stock	(819)	(799)
Proceeds from employee stock plans	24	25
Other financing activities	(65)	(158)
Net cash flows provided by financing activities	5,402	887
Increase in cash and cash equivalents	5,387	1,154
Cash and cash equivalents at beginning of period	1,878	1,609
Cash and cash equivalents at end of period	$ 7,265	$ 2,763

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 7,265	$ 1,878
Restricted cash and cash equivalents	341	271
Accounts receivable, net		
Customer	3,215	3,482
Other	1,107	1,227
Mark-to-market derivative assets	1,116	1,279
Unamortized energy contract assets	135	254
Inventories, net		
Fossil fuel and emission allowances	442	579
Materials and supplies	1,074	1,024
Deferred income taxes	211	244
Regulatory assets	779	847
Assets held for sale	4	147
Other	1,178	865
Total current assets	16,867	12,097
Property, plant and equipment, net	55,814	52,087
Deferred debits and other assets		
Regulatory assets	6,000	6,076
Nuclear decommissioning trust funds	10,103	10,537
Investments	620	544
Goodwill	2,672	2,672
Mark-to-market derivative assets	801	773
Deferred income taxes	2	—
Unamortized energy contracts assets	513	549
Pledged assets for Zion Station decommissioning	237	319
Other	1,499	1,160
Total deferred debits and other assets	22,447	22,630
Total assets[a]	$ 95,128	$ 86,814

See the Combined Notes to Consolidated Financial Statements

EXELON CORPORATION AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 675	$ 460
Long-term debt due within one year	897	1,802
Accounts payable	2,987	3,048
Accrued expenses	1,576	1,539
Payables to affiliates	8	8
Regulatory liabilities	365	310
Mark-to-market derivative liabilities	204	234
Unamortized energy contract liabilities	118	238
Other	1,017	1,123
Total current liabilities	7,847	8,762
Long-term debt	24,541	19,362
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,480	13,019
Asset retirement obligations	8,405	7,295
Pension obligations	3,014	3,366
Non-pension postretirement benefit obligations	1,877	1,742
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,180	4,550
Mark-to-market derivative liabilities	360	403
Unamortized energy contract liabilities	136	211
Payable for Zion Station decommissioning	99	155
Other	2,231	2,147
Total deferred credits and other liabilities	34,803	33,909
Total liabilities[(a)]	67,839	62,681
Commitments and contingencies		
Shareholders' equity		
Common stock (No par value, 2,000 shares authorized, 920 shares and 860 shares outstanding at September 30, 2015 and December 31, 2014, respectively)	18,647	16,709
Treasury stock, at cost (35 shares at both September 30, 2015 and December 31, 2014)	(2,327)	(2,327)
Retained earnings	12,046	10,910
Accumulated other comprehensive loss, net	(2,596)	(2,684)
Total shareholders' equity	25,770	22,608
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,326	1,332
Total equity	27,289	24,133
Total liabilities and shareholders' equity	$ 95,128	$ 86,814

(a) Exelon's consolidated assets include $8,190 million and $8,160 million at September 30, 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 $3,242 million and $2,723 million at September 30, 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.

See the Combined Notes to Consolidated Financial Statements

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
Balance, December 31, 2014	894,568	$16,709	$(2,327)	$10,910	$ (2,684)	$ 1,332	$ 193	$24,133
Net income	—	—	—	1,959	—	(10)	10	1,959
Long-term incentive plan activity	1,394	47	—	—	—	—	—	47
Employee stock purchase plan issuances	1,083	24	—	—	—	—	—	24
Issuance of common stock	57,500	1,868	—	—	—	—	—	1,868
Tax benefit on stock compensation	—	(1)	—	—	—	—	—	(1)
Changes in equity of noncontrolling interest	—	—	—	—	—	4	—	4
Common stock dividends	—	—	—	(823)	—	—	—	(823)
Preference stock dividends	—	—	—	—	—	—	(10)	(10)
Other comprehensive income, net of income taxes	—	—	—	—	88	—	—	88
Balance, September 30, 2015	954,545	$18,647	$(2,327)	$12,046	$ (2,596)	$ 1,326	$ 193	$27,289

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenues				
Operating revenues	$ 4,562	$ 4,300	$14,270	$11,944
Operating revenues from affiliates	206	112	571	647
Total operating revenues	4,768	4,412	14,841	12,591
Operating expenses				
Purchased power and fuel	2,516	1,821	7,789	6,595
Purchased power and fuel from affiliates	3	59	11	476
Operating and maintenance	1,088	1,114	3,399	3,308
Operating and maintenance from affiliates	153	152	461	457
Depreciation and amortization	264	253	774	719
Taxes other than income	123	127	369	350
Total operating expenses	4,147	3,526	12,803	11,905
Equity in earnings (losses) of unconsolidated affiliates	—	1	—	(20)
Gain on sales of assets	1	338	7	355
Gain on consolidation and acquisition of businesses	—	—	—	261
Operating income	622	1,225	2,045	1,282
Other income and (deductions)				
Interest expense	(56)	(77)	(236)	(224)
Interest expense to affiliates, net	(12)	(12)	(33)	(37)
Other, net	(257)	4	(193)	306
Total other income and (deductions)	(325)	(85)	(462)	45
Income before income taxes	297	1,140	1,583	1,327
Income taxes	(36)	291	371	290
Equity in losses of unconsolidated affiliates	(1)	—	(4)	—
Net income	332	849	1,208	1,037
Net income (loss) attributable to noncontrolling interests	(45)	78	(10)	111
Net income attributable to membership interest	$ 377	$ 771	$ 1,218	$ 926
Comprehensive income, net of income taxes				
Net income	$ 332	$ 849	$ 1,208	$ 1,037
Other comprehensive income (loss), net of income taxes				
Unrealized loss on cash flow hedges	(3)	(16)	(7)	(86)
Unrealized gain (loss) on equity investments	—	(3)	—	8
Unrealized loss on foreign currency translation	(8)	(5)	(17)	(6)
Unrealized loss on marketable securities	(2)	(2)	—	(3)
Reversal of CENG equity method AOCI	—	—	—	(116)
Other comprehensive loss	(13)	(26)	(24)	(203)
Comprehensive income	$ 319	$ 823	$ 1,184	$ 834

See the Combined Notes to Consolidated Financial Statements

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

(In millions)	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities		
Net income	$ 1,208	$ 1,037
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	1,887	1,853
Impairment of long-lived assets	1	138
Gain on consolidation and acquisitions of businesses	—	(268)
Gain on sales of assets	(7)	(355)
Deferred income taxes and amortization of investment tax credits	21	154
Net fair value changes related to derivatives	(252)	509
Net realized and unrealized (gains) losses on nuclear decommissioning trust fund investments	221	(141)
Other non-cash operating activities	227	251
Changes in assets and liabilities:		
Accounts receivable	252	153
Receivables from and payables to affiliates, net	16	72
Inventories	69	(286)
Accounts payable, accrued expenses and other current liabilities	(156)	(311)
Option premiums received, net	27	21
Counterparty collateral received (posted), net	376	(634)
Income taxes	(70)	172
Pension and non-pension postretirement benefit contributions	(189)	(214)
Other assets and liabilities	(425)	(367)
Net cash flows provided by operating activities	3,206	1,784
Cash flows from investing activities		
Capital expenditures	(2,774)	(1,961)
Proceeds from nuclear decommissioning trust fund sales	4,551	5,464
Investment in nuclear decommissioning trust funds	(4,737)	(5,550)
Acquisition of businesses	(28)	(67)
Proceeds from sale of long-lived assets	144	660
Change in restricted cash	(84)	(116)
Changes in Exelon intercompany money pool	—	44
Cash and restricted cash acquired from consolidations and acquisitions	—	129
Other investing activities	(92)	(34)
Net cash flows used in investing activities	(3,020)	(1,431)
Cash flows from financing activities		
Change in short-term borrowings	—	7
Issuance of long-term debt	1,307	1,112
Retirement of long-term debt	(64)	(552)
Retirement of long-term debt to affiliate	(550)	—
Changes in Exelon intercompany money pool	1,205	—
Distribution to member	(2,368)	(440)
Distributions to noncontrolling interest of consolidated VIE	—	(415)
Contribution from member	55	55
Other financing activities	(6)	(67)
Net cash flows used in financing activities	(421)	(300)
Increase (decrease) in cash and cash equivalents	(235)	53
Cash and cash equivalents at beginning of period	780	1,258
Cash and cash equivalents at end of period	$ 545	$ 1,311

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 545	$ 780
Restricted cash and cash equivalents	242	158
Accounts receivable, net		
Customer	2,056	2,295
Other	487	318
Mark-to-market derivative assets	1,116	1,276
Receivables from affiliates	84	113
Unamortized energy contract assets	135	254
Inventories, net		
Fossil fuel and emission allowances	357	465
Materials and supplies	863	847
Deferred income taxes	201	327
Assets held for sale	4	147
Other	960	658
Total current assets	7,050	7,638
Property, plant and equipment, net	24,982	22,945
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,103	10,537
Investments	197	104
Goodwill	47	47
Mark-to-market derivative assets	764	771
Prepaid pension asset	1,703	1,704
Pledged assets for Zion Station decommissioning	237	319
Unamortized energy contract assets	513	549
Deferred income taxes	2	3
Other	881	731
Total deferred debits and other assets	14,447	14,765
Total assets[(a)]	$ 46,479	$ 45,348

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 21	$ 36
Long-term debt due within one year	97	58
Long-term debt to affiliates due within one year	—	556
Accounts payable	1,676	1,759
Accrued expenses	835	886
Payables to affiliates	106	107
Borrowings from Exelon intercompany money pool	1,205	—
Mark-to-market derivative liabilities	182	214
Unamortized energy contract liabilities	118	238
Other	546	605
Total current liabilities	4,786	4,459
Long-term debt	7,964	6,709
Long-term debt to affiliate	935	943
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,030	6,034
Asset retirement obligations	8,254	7,146
Non-pension postretirement benefit obligations	926	915
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,538	2,880
Mark-to-market derivative liabilities	139	105
Unamortized energy contract liabilities	136	211
Payable for Zion Station decommissioning	99	155
Other	727	719
Total deferred credits and other liabilities	19,870	19,186
Total liabilities[(a)]	33,555	31,297
Commitments and contingencies		
Equity		
Member's equity		
Membership interest	9,006	8,951
Undistributed earnings	2,653	3,803
Accumulated other comprehensive loss, net	(60)	(36)
Total member's equity	11,599	12,718
Noncontrolling interest	1,325	1,333
Total equity	12,924	14,051
Total liabilities and equity	$ 46,479	$ 45,348

(a) Generation's consolidated assets include $8,130 million and $8,119 million at September 30, 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 $3,070 million and $2,507 million at September 30, 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.

See the Combined Notes to Consolidated Financial Statements

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY
(Unaudited)

	Member's Equity				
(In millions)	Membership Interest	Undistributed Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Total Equity
Balance, December 31, 2014	$ 8,951	$ 3,803	$ (36)	$ 1,333	$14,051
Net income	—	1,218	—	(10)	1,208
Changes in equity of noncontrolling interest	—	—	—	2	2
Allocation of tax benefit from member	55	—	—	—	55
Distribution to member	—	(2,368)	—	—	(2,368)
Other comprehensive loss, net of income taxes	—	—	(24)	—	(24)
Balance, September 30, 2015	$ 9,006	$ 2,653	$ (60)	$ 1,325	$12,924

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenues				
Operating revenues	$ 1,375	$ 1,221	$3,706	$ 3,482
Operating revenues from affiliates	1	1	3	2
Total operating revenues	1,376	1,222	3,709	3,484
Operating expenses				
Purchased power	388	325	974	741
Purchased power from affiliate	2	1	17	174
Operating and maintenance	353	320	1,023	923
Operating and maintenance from affiliate	51	39	143	117
Depreciation and amortization	176	174	528	521
Taxes other than income	79	76	225	225
Total operating expenses	1,049	935	2,910	2,701
Operating income	327	287	799	783
Other income and (deductions)				
Interest expense, net	(80)	(78)	(238)	(231)
Interest expense to affiliates	(3)	(3)	(10)	(10)
Other, net	4	4	14	14
Total other income and (deductions)	(79)	(77)	(234)	(227)
Income before income taxes	248	210	565	556
Income taxes	99	84	226	221
Net income	149	126	339	335
Comprehensive income	$ 149	$ 126	$ 339	$ 335

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities		
Net income	$ 339	$ 335
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	528	521
Deferred income taxes and amortization of investment tax credits	107	154
Other non-cash operating activities	312	116
Changes in assets and liabilities:		
Accounts receivable	(114)	(109)
Receivables from and payables to affiliates, net	(23)	(55)
Inventories	(23)	(12)
Accounts payable, accrued expenses and other current liabilities	(20)	59
Income taxes	389	15
Pension and non-pension postretirement benefit contributions	(142)	(237)
Other assets and liabilities	(7)	62
Net cash flows provided by operating activities	1,346	849
Cash flows from investing activities		
Capital expenditures	(1,670)	(1,173)
Proceeds from sales of investments	—	7
Change in restricted cash	2	(2)
Other investing activities	22	20
Net cash flows used in investing activities	(1,646)	(1,148)
Cash flows from financing activities		
Changes in short-term borrowings	300	344
Issuance of long-term debt	400	650
Retirement of long-term debt	(260)	(617)
Contributions from parent	75	168
Dividends paid on common stock	(226)	(230)
Other financing activities	(4)	(8)
Net cash flows provided by financing activities	285	307
Increase (decrease) in cash and cash equivalents	(15)	8
Cash and cash equivalents at beginning of period	66	36
Cash and cash equivalents at end of period	$ 51	$ 44

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 51	$ 66
Restricted cash	2	4
Accounts receivable, net		
Customer	557	477
Other	334	648
Receivables from affiliates	14	14
Inventories, net	148	125
Regulatory assets	232	349
Other	84	40
Total current assets	1,422	1,723
Property, plant and equipment, net	17,001	15,793
Deferred debits and other assets		
Regulatory assets	913	852
Goodwill	2,625	2,625
Receivables from affiliates	2,336	2,571
Prepaid pension asset	1,537	1,551
Other	295	277
Total deferred debits and other assets	7,706	7,876
Total assets	$ 26,129	$ 25,392

See the Combined Notes to Consolidated Financial Statements

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 604	$ 304
Long-term debt due within one year	665	260
Accounts payable	693	598
Accrued expenses	337	331
Payables to affiliates	60	84
Customer deposits	130	128
Regulatory liabilities	144	125
Deferred income taxes	—	63
Mark-to-market derivative liability	22	20
Other	68	73
Total current liabilities	2,723	1,986
Long-term debt	5,435	5,698
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,677	4,498
Asset retirement obligations	110	103
Non-pension postretirement benefits obligations	262	263
Regulatory liabilities	3,441	3,655
Mark-to-market derivative liability	221	187
Other	954	889
Total deferred credits and other liabilities	9,665	9,595
Total liabilities	18,029	17,485
Commitments and contingencies		
Shareholders' equity		
Common stock	1,588	1,588
Other paid-in capital	5,548	5,468
Retained earnings	964	851
Total shareholders' equity	8,100	7,907
Total liabilities and shareholders' equity	$ 26,129	$ 25,392

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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
Balance, December 31, 2014	$ 1,588	$ 5,468	$ (1,639)	$ 2,490	$ 7,907
Net income	—	—	339	—	339
Appropriation of retained earnings for future dividends	—	—	(339)	339	—
Common stock dividends	—	—	—	(226)	(226)
Contribution from parent	—	75	—	—	75
Parent tax matter indemnification	—	5	—	—	5
Balance, September 30, 2015	$ 1,588	$ 5,548	$ (1,639)	$ 2,603	$ 8,100

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
(Unaudited)

(In millions)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenues				
Operating revenues	$ 739	$ 693	$ 2,385	$ 2,342
Operating revenues from affiliates	1	—	1	1
Total operating revenues	740	693	2,386	2,343
Operating expenses				
Purchased power and fuel	217	228	782	798
Purchased power from affiliate	61	27	171	162
Operating and maintenance	166	181	529	597
Operating and maintenance from affiliates	30	23	80	71
Depreciation and amortization	68	59	198	176
Taxes other than income	44	42	125	122
Total operating expenses	586	560	1,885	1,926
Gain on sale of assets	—	—	1	—
Operating income	154	133	502	417
Other income and (deductions)				
Interest expense, net	(25)	(26)	(75)	(76)
Interest expense to affiliates	(3)	(3)	(9)	(9)
Other, net	1	2	3	5
Total other income and (deductions)	(27)	(27)	(81)	(80)
Income before income taxes	127	106	421	337
Income taxes	37	25	122	82
Net income attributable to common shareholder	90	81	299	255
Comprehensive income	$ 90	$ 81	$ 299	$ 255

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Cash flows from operating activities		
Net income	$ 299	$ 255
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	198	176
Deferred income taxes and amortization of investment tax credits	11	7
Other non-cash operating activities	69	70
Changes in assets and liabilities:		
Accounts receivable	(15)	63
Receivables from and payables to affiliates, net	—	(20)
Inventories	8	5
Accounts payable, accrued expenses and other current liabilities	(17)	19
Income taxes	69	16
Pension and non-pension postretirement benefit contributions	(37)	(12)
Other assets and liabilities	(18)	(75)
Net cash flows provided by operating activities	567	504
Cash flows from investing activities		
Capital expenditures	(435)	(461)
Change in restricted cash	(1)	—
Other investing activities	11	9
Net cash flows used in investing activities	(425)	(452)
Cash flows from financing activities		
Issuance of long-term debt	—	300
Contributions from parent	16	24
Change in Exelon intercompany money pool	55	—
Dividends paid on common stock	(209)	(240)
Other financing activities	(2)	(7)
Net cash flows provided by (used in) financing activities	(140)	77
Increase in cash and cash equivalents	2	129
Cash and cash equivalents at beginning of period	30	217
Cash and cash equivalents at end of period	$ 32	$ 346

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 32	$ 30
Restricted cash and cash equivalents	3	2
Accounts receivable, net		
Customer	283	320
Other	122	141
Receivables from affiliates	4	3
Inventories, net		
Fossil fuel	43	57
Materials and supplies	28	22
Deferred income taxes	69	69
Prepaid utility taxes	42	10
Regulatory assets	32	29
Other	25	31
Total current assets	683	714
Property, plant and equipment, net	7,027	6,801
Deferred debits and other assets		
Regulatory assets	1,557	1,529
Investments	28	31
Receivable from affiliates	388	490
Prepaid pension asset	353	344
Other	36	34
Total deferred debits and other assets	2,362	2,428
Total assets	$ 10,072	$ 9,943

See the Combined Notes to Consolidated Financial Statements

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 298	$ 337
Accrued expenses	123	91
Payables to affiliates	53	52
Borrowings from Exelon intercompany money pool	55	—
Customer deposits	56	52
Regulatory liabilities	104	90
Other	30	31
Total current liabilities	719	653
Long-term debt	2,246	2,246
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,752	2,671
Asset retirement obligations	26	29
Non-pension postretirement benefits obligations	288	287
Regulatory liabilities	536	657
Other	94	95
Total deferred credits and other liabilities	3,696	3,739
Total liabilities	6,845	6,822
Commitments and contingencies		
Shareholder's equity		
Common stock	2,455	2,439
Retained earnings	771	681
Accumulated other comprehensive income, net	1	1
Total shareholder's equity	3,227	3,121
Total liabilities and shareholder's equity	$ 10,072	$ 9,943

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 Equity
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$3,121
Net income	—	299	—	299
Allocation of tax benefit from parent	16	—	—	16
Common stock dividends	—	(209)	—	(209)
Balance, September 30, 2015	$ 2,455	$ 771	$ 1	$3,227

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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 September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Operating revenue				
Operating revenue	$ 722	$ 694	$ 2,378	$ 2,383
Operating revenue from affiliates	3	3	10	21
Total operating revenues	725	697	2,388	2,404
Operating expenses				
Purchased power and fuel	170	216	664	808
Purchased power from affiliate	141	81	373	286
Operating and maintenance	138	142	412	468
Operating and maintenance from affiliates	31	23	87	73
Depreciation and amortization	79	78	271	275
Taxes other than income	57	55	169	168
Total operating expenses	616	595	1,976	2,078
Gain on sale of assets	1	—	1	—
Operating income	110	102	413	326
Other income and (deductions)				
Interest expense, net	(21)	(22)	(62)	(69)
Interest expense to affiliates	(4)	(4)	(11)	(12)
Other, net	4	4	13	14
Total other income and (deductions)	(21)	(22)	(60)	(67)
Income before income taxes	89	80	353	259
Income taxes	35	31	141	103
Net income	54	49	212	156
Preference stock dividends	3	3	10	10
Net income attributable to common shareholder	51	46	202	146
Comprehensive income	$ 54	$ 49	$ 212	$ 156

See the Combined Notes to Consolidated Financial Statements

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(In millions)	Nine Months Ended September 30, 2015	2014
Cash flows from operating activities		
Net income	$ 212	$ 156
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	271	275
Deferred income taxes and amortization of investment tax credits	79	57
Other non-cash operating activities	111	129
Changes in assets and liabilities:		
Accounts receivable	62	101
Receivables from and payables to affiliates, net	(8)	(11)
Inventories	10	(21)
Accounts payable, accrued expenses and other current liabilities	49	(50)
Counterparty collateral (posted) received, net	(27)	16
Income taxes	(6)	53
Pension and non-pension postretirement benefit contributions	(14)	(13)
Other assets and liabilities	(43)	(67)
Net cash flows provided by operating activities	696	625
Cash flows from investing activities		
Capital expenditures	(506)	(458)
Change in restricted cash	2	(37)
Other investing activities	13	15
Net cash flows used in investing activities	(491)	(480)
Cash flows from financing activities		
Changes in short-term borrowings	(70)	(115)
Retirement of long-term debt	(37)	(35)
Contributions from parent	6	—
Dividends paid on preference stock	(10)	(10)
Dividends paid on common stock	(116)	—
Other financing activities	(15)	11
Net cash flows used in financing activities	(242)	(149)
Decrease in cash and cash equivalents	(37)	(4)
Cash and cash equivalents at beginning of period	64	31
Cash and cash equivalents at end of period	$ 27	$ 27

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 27	$ 64
Restricted cash and cash equivalents	48	50
Accounts receivable, net		
Customer	318	390
Other	77	82
Receivables from affiliates	1	—
Inventories, net		
Gas held in storage	42	57
Materials and supplies	35	30
Deferred income taxes	8	6
Prepaid utility taxes	4	59
Regulatory assets	257	214
Other	5	5
Total current assets	822	957
Property, plant and equipment, net	6,459	6,204
Deferred debits and other assets		
Regulatory assets	485	510
Investments	12	12
Prepaid pension asset	331	370
Other	25	25
Total deferred debits and other assets	853	917
Total assets[a]	$ 8,134	$ 8,078

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	September 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current liabilities		
Short-term borrowings	$ 50	$ 120
Long-term debt due within one year	77	75
Accounts payable	201	215
Accrued expenses	159	131
Deferred income taxes	63	52
Payables to affiliates	47	66
Customer deposits	99	92
Regulatory liabilities	69	44
Other	32	51
Total current liabilities	797	846
Long-term debt	1,828	1,867
Long-term debt to financing trust	258	258
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,937	1,865
Asset retirement obligations	15	17
Non-pension postretirement benefits obligations	209	212
Regulatory liabilities	186	200
Other	59	60
Total deferred credits and other liabilities	2,406	2,354
Total liabilities[(a)]	5,289	5,325
Commitments and contingencies		
Shareholders' equity		
Common stock	1,366	1,360
Retained earnings	1,289	1,203
Total shareholders' equity	2,655	2,563
Preference stock not subject to mandatory redemption	190	190
Total equity	2,845	2,753
Total liabilities and shareholders' equity	$ 8,134	$ 8,078

(a) BGE's consolidated assets include $49 million and $24 million at September 30, 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 $162 million and $197 million at September 30, 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

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
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$ 2,753
Net income	—	212	212	—	212
Allocation of tax benefit from parent	6	—	6	—	6
Preference stock dividends	—	(10)	(10)	—	(10)
Common stock dividends	—	(116)	(116)	—	(116)
Balance, September 30, 2015	$ 1,366	$ 1,289	$ 2,655	$ 190	$ 2,845

See the Combined Notes to Consolidated Financial Statements

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Dollars in millions, except per share data, unless otherwise noted)

Index to Combined Notes to Consolidated Financial Statements

The notes to the consolidated financial statements that follow are a combined presentation. The following list indicates the registrants to which the footnotes apply:

Applicable Notes

Registrant	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
Exelon Corporation	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.
Exelon Generation Company, LLC	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.	.			.		.
Commonwealth Edison Company	.	.	.		.				.	.	.	.		.	.				.		.
PECO Energy Company	.	.	.		.				.	.	.	.		.	.	.			.		.
Baltimore Gas And Electric Company	.	.	.		.				.	.	.	.		.	.				.		.

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 Registrants' 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 have been presented below Income taxes in the Registrants' Consolidated Statements of Operations and Comprehensive Income starting in the first quarter of 2015.

For the three months ended September 30, 2015, Generation recorded a $52 million (pre-tax) correcting adjustment to decrease mark-to-market income level 3 derivative contract valuations, of which $12 million (pre-tax) was originally recorded during 2014 and $40 million (pre-tax) was originally recorded during the first and second quarter of 2015. Exelon and Generation have concluded that this correcting adjustment is not material to their respective results of operations for the three and nine months ended September 30, 2015 or cash flows for the nine months ended September 30, 2015 or any prior period presented. Exelon and Generation do not expect this correcting adjustment to have a material impact on their respective results of operations or cash flows for the year ended December 31, 2015.

The accompanying consolidated financial statements as of September 30, 2015 and 2014 and for the nine 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 Registrants' 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.

2. New Accounting Pronouncements (Exelon, Generation, ComEd, PECO and BGE)

The following recently issued accounting standard was effective for the Registrants during 2015.

Application of Normal Purchases Normal Sales Exception to Power Contracts in Nodal Energy Markets

In August 2015, the FASB issued authoritative guidance addressing the ability of entities to elect the normal purchase normal sales (NPNS) scope exception when the contract for the purchase or sale of electricity on a forward basis is delivered to a nodal energy market or transmitted through a nodal energy market. The NPNS scope exception allows entities to treat certain contracts that qualify as derivatives as contracts that do not require recognition at fair value. The guidance specifies that the use of locational marginal pricing by an independent system operator in such transactions does not constitute net settlement of a contract for the purchase or sale of electricity, even in scenarios in which legal title to the associated electricity is conveyed to the independent system operator during transmission. Consequently, the use of locational marginal pricing by the independent system operator does not cause that contract to fail to meet the physical delivery criterion of the NPNS scope exception. If the physical delivery criterion is met, along with all of the other criteria of the NPNS scope exception, an entity may elect to designate that contract as NPNS. The guidance is effective upon issuance and should be applied prospectively. The adoption of this guidance had no impact on the Registrants' financial positions, results of operations, cash flows and disclosures.

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

Simplifying the Accounting for Measurement-Period Adjustments

In September 2015, the FASB issued authoritative guidance that requires an acquirer in a business combination to recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined and to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The guidance is effective for periods beginning after December 15, 2015. The guidance is required to be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. The Registrants expect to early adopt the standard in the fourth quarter of 2015. The adoption of this guidance will have no impact on the Registrants' financial positions, results of operations, cash flows and disclosures.

Simplifying the Measurement of Inventory

In July 2015, the FASB issued authoritative guidance that requires inventory to be measured at the lower of cost or net realizable value. The new guidance defines net realizable value as the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This definition is consistent with existing authoritative guidance. Current guidance requires inventory to be measured at the lower of cost or market where market could be replacement cost, net realizable value or net realizable value less an approximately normal profit margin. The guidance is effective for periods beginning after December 15, 2016 with early adoption permitted. The guidance is required to be applied prospectively. 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 potential to early adopt the guidance.

Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share

In May 2015, FASB issued authoritative guidance that removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. Investments measured at net asset value per share using the practical expedient will be presented as a reconciling item between the fair value hierarchy disclosure and the investment line item on the statement of financial position. The guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Rather, those disclosures are limited to investments for which the entity has elected to measure the fair value using the practical expedient. The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015 with early adoption permitted. The guidance is required to be applied retrospectively to all prior periods presented. The Registrants are currently assessing the impacts this guidance may have on their disclosures as well as the potential to early adopt the guidance. There will be no impact to their financial position, results of operations or cash flows.

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 do not expect that this guidance will have a significant impact on their financial positions, results of operations, cash flows and disclosures. The Registrants expect to apply the standard prospectively to arrangements entered into, or materially modified, after the standard becomes effective for the Registrants on January 1, 2016. The Registrants do not plan to early adopt the standard.

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

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 entities 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. The standard will not impact the results of operations and cash flows of the Registrants. The Registrants expect to complete their assessment by the fourth quarter of 2015 and early adopt the standard at that time.

In August 2015, the FASB issued clarifying authoritative guidance for debt issuance costs incurred in connection with line-of-credit arrangements as such costs were not addressed within the guidance simplifying the presentation of debt issuance costs issued in April 2015. The guidance clarifies that an entity can defer and present debt issuance costs as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement. The adoption of this guidance will have no impact on the Registrants' financial positions, results of operations, cash flows and disclosures.

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 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 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. In August 2015, the FASB issued an amendment to provide a one year deferral of the effective date to annual reporting periods beginning on or after December 15, 2017, as well as an option to early adopt the standard for annual periods beginning on or after December 15, 2016. The Registrants do not plan to early adopt the standard.

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

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 September 30, 2015 and December 31, 2014, Exelon, Generation, and BGE collectively consolidated seven and six VIEs or VIE groups, respectively, for which the applicable Registrant was the primary beneficiary *(see Consolidated Variable Interest Entities below)*. As of September 30, 2015 and December 31, 2014, the Registrants had significant interests in eight 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 (see Unconsolidated Variable Interest Entities below).

During the second quarter of 2015 Generation added a new group of consolidated VIEs named "a group of companies formed by Generation to build, own, and operate other generating facilities." The new group is comprised of a biomass fueled, combined heat and power facility and a backup generator company for which Generation is the primary beneficiary. Generation provides parental guarantees for up to $275 million in support of the payment obligations related to the Engineering, Procurement and Construction contract for Albany Green Energy, LLC (see Note 11 — Debt and Credit Agreements for additional details).

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,
- a group of companies formed by Generation to build, own and operate other generating facilities,
- certain retail power and gas companies for which Generation is the sole supplier of energy, and
- CENG.

As of September 30, 2015 and December 31, 2014, ComEd and PECO do not have any material consolidated VIEs.

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

As of September 30, 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 and nine months ended September 30, 2015, BGE remitted $21 million and $63 million to BondCo, respectively. During the three and nine months ended September 30, 2014, BGE remitted $21 million and $63 million to BondCo, respectively.
- Generation provides operating and capital funding to the solar and wind entities for ongoing construction, operations and maintenance of the solar and wind power facilities and there is limited recourse to Generation 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 not subject to other contractual agreements 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 expected Reliability Support Services Agreement (RSSA). Ginna originally entered into an agreement with Rochester Gas and Electric Corporation (RG&E) on February 13, 2015; however, final terms and conditions are currently under negotiation. The obligations under the RSSA are expected to commence retroactive back to April 1, 2015 and run through March 31, 2017 (see Note 5 — Regulatory Matters for additional details),
  - Generation provided a $400 million loan to CENG. As of September 30, 2015, the remaining obligation is $296 million including accrued interest, 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 19 — Commitments and Contingencies for more details),
  - 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 September 30, 2015, the remaining obligation is approximately $1 million,

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

- 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 19 — Commitments and Contingencies for more details),
- 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 19 — 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 $11 million in credit support for the retail power and gas 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 September 30, 2015 and December 31, 2014 are as follows:

	September 30, 2015			December 31, 2014		
	Exelon[(a)]	Generation	BGE	Exelon[(a)]	Generation	BGE
Current assets	$ 1,108	$ 1,057	$ 46	$ 1,271	$ 1,242	$ 21
Noncurrent assets	7,736	7,728	3	7,580	7,566	3
Total assets	$ 8,844	$ 8,785	$ 49	$ 8,851	$ 8,808	$ 24
Current liabilities	$ 494	$ 408	$ 81	$ 611	$ 526	$ 77
Noncurrent liabilities	2,859	2,773	81	2,730	2,600	120
Total liabilities	$ 3,353	$ 3,181	$162	$ 3,341	$ 3,126	$197

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

(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 September 30, 2015 and December 31, 2014, these assets and liabilities primarily consisted of the following:

	September 30, 2015			December 31, 2014		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 330	$ 330	$ —	$ 392	$ 392	$ —
Restricted cash	193	146	46	117	96	21
Accounts receivable, net						
Customer	186	186	—	297	297	—
Other	32	32	—	57	57	—
Mark-to-market derivatives assets	116	116	—	171	171	—
Inventory						
Materials and supplies	180	180	—	172	172	—
Other current assets	48	43	—	33	26	—
Total current assets	1,085	1,033	46	1,239	1,211	21
Property, plant and equipment, net	4,932	4,932	—	4,638	4,638	—
Nuclear decommissioning trust funds	1,973	1,973	—	2,097	2,097	—
Goodwill	47	47	—	47	47	—
Mark-to-market derivatives assets	53	53	—	44	44	—
Other noncurrent assets	100	92	3	95	82	3
Total noncurrent assets	7,105	7,097	3	6,921	6,908	3
Total assets	$8,190	$ 8,130	$ 49	$8,160	$ 8,119	$ 24
Long-term debt due within one year	$ 108	$ 26	$ 77	$ 87	$ 5	$ 75
Accounts payable	266	266	—	292	292	—
Accrued expenses	92	88	4	111	108	2
Mark-to-market derivative liabilities	—	—	—	24	24	—
Unamortized energy contract liabilities	10	10	—	22	22	—
Other current liabilities	15	15	—	25	25	—
Total current liabilities	491	405	81	561	476	77
Long-term debt	729	643	81	212	81	120
Asset retirement obligations	1,906	1,906	—	1,763	1,763	—
Pension obligation[(a)]	9	9	—	9	9	—
Unamortized energy contract liabilities	42	42	—	51	51	—
Other noncurrent liabilities	65	65	—	127	127	—
Noncurrent liabilities	2,751	2,665	81	2,162	2,031	120
Total liabilities	$3,242	$ 3,070	$162	$2,723	$ 2,507	$197

(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 14 — Retirement Benefits for additional details.

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, distributed energy companies, and energy generating facilities for which Generation has concluded that consolidation is not required.

As of September 30, 2015 and December 31, 2014, Exelon and Generation had significant unconsolidated variable interests in eight and six VIEs, respectively, for which Exelon or Generation, as applicable, was not the primary beneficiary; including certain equity 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 and an equity investment in a new unconsolidated VIE.

In June 2015, 2015 ESA Investco, LLC, a wholly owned subsidiary of Generation, entered into an arrangement to purchase a 90% equity interest and 99% of the tax attributes of a distributed energy company. Equity will be contributed incrementally over an eighteen month period and will total approximately $250 million (see Note 19 — Commitments and Contingencies for additional details). Generation provides a parental guarantee of up to $275 million in support of 2015 ESA Investco, LLC's obligation to make equity contributions to the VIE. The investment was evaluated and it was determined to be a VIE for which Generation is not the primary beneficiary. Separate from the equity investment, Generation provided $27 million in cash to the other (10%) equity holder in the distributed energy company in exchange for a convertible promissory note. In July 2014, Generation entered into another arrangement with the same equity holder for the purchase of a 90% equity interest and 90% of the tax attributes of another distributed energy company. Generation's total equity commitment in this arrangement was $91 million and is paid incrementally over an approximate two year period (see Note 19 — Commitments and Contingencies for additional details). This arrangement did not meet the definition of a VIE and is recorded as an equity method investment. Both distributed energy companies are considered related parties.

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

The following tables present summary information about Exelon and Generation's significant unconsolidated VIE entities:

September 30, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 253	$ 131	$384
Total liabilities[(a)]	10	66	76
Exelon's ownership interest in VIE[(a)]	—	19	19
Other ownership interests in VIE[(a)]	243	46	289
Registrants' maximum exposure to loss:			
Carrying amount of equity method investments	—	27	27
Contract intangible asset	9	—	9
Debt and payment guarantees	—	3	3
Net assets pledged for Zion Station decommissioning[(b)]	20	—	20

December 31, 2014	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[(a)]	$ 114	$ 91	$205
Total liabilities[(a)]	3	49	52
Exelon's ownership interest in VIE[(a)]	—	9	9
Other ownership interests in VIE[(a)]	111	33	144
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[(b)]	27	—	27

(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. Exelon corrected an error in the December 31, 2014 balances within Commercial Agreement VIEs for an overstatement of Total assets, Total liabilities and Other ownership interests in VIE of $392 million, $234 million and $158 million, respectively. The error is not considered material to any prior period.

(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 $237 million and $319 million as of September 30, 2015 and December 31, 2014, respectively; offset by payables to ZionSolutions, LLC of $217 million and $292 million as of September 30, 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 (Exelon and Generation)

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. Based on the outstanding shares of PHI's common stock as of September 30, 2015, PHI shareholders would receive $6.9 billion in total cash. In addition, in connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $180 million of a class of nonvoting, nonconvertible and nontransferable preferred securities of PHI. 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.

On September 9, 2014, Exelon and PHI filed a Notification and Report Form with DOJ under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act). 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. Under the HSR Act, if the merger is not completed before December 23, 2015, Exelon and PHI are required to file again under the HSR Act and observe the required waiting period, which is 30 days from the new filing (and longer if the DOJ requests additional information), unless the DOJ terminates the waiting period earlier. Exelon and PHI intend to withdraw our pending HSR application and refile under the HSR Act on November 2, 2015. This will trigger a new 30-day waiting period. Unless a request for additional information is issued by DOJ during that waiting period, the waiting period will expire on December 2, 2015, and the parties will be free to close on or after December 2.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) 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 NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million. The March 6, 2015, order by the NJBPU approving the merger required that the consummation of the merger must take place no later than November 1, 2015 unless otherwise extended by the Board. On October 15, 2015, the NJBPU extended the November 1, 2015 date to June 30, 2016.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, 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 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 June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George's County, The Alliance for Solar Choice, the National Consumer Law Center, National Housing Trust, the 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. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development, ring-fencing, financial reporting conditions and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People's Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC's approval of the merger with the Circuit Court for Queen Anne's County. On June 23, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne's County. On July 10, 2015, Exelon and PHI filed a response in opposition to the Petitions for Review.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC's motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George's County and Montgomery County filed responses opposing the motions to stay. The presiding judge issued an order denying the motions for stay on August 12, 2015. A hearing on the underlying Petitions for Review is scheduled for December 8, 2015.

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, asserting that the merger was not in the public's interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, Exelon, PHI, the District of Columbia Government, the Office of Peoples Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust — Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties) entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief. The new package of benefits totals $78 million and includes commitments to provide relief of residential customer base rate increases of $26 million, one-time direct bill credits of $14 million, low-income energy assistance of $16 million, improved reliability, a cleaner and greener D.C. through funding energy efficiency programs and development of renewable energy, and investment in local jobs and the local economy through workforce development of $5 million. It also guarantees charitable contributions totaling $19 million over 10 years.

On October 28, 2015, the DCPSC at a public meeting agreed to reopen the approval application to allow for consideration of the Settlement Agreement and set a procedural schedule which would allow for completion of the merger in the first quarter of 2016. If the DCPSC does not approve the Settlement Agreement within the 150 day period after it was filed, either Exelon or PHI may terminate the Settlement Agreement.

The settlements reached and commission orders received to date in Delaware, Maryland and New Jersey include a “most favored nation” provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions. When applying the most favored nation provision to the settlement terms and other conditions established in the merger approvals received to date, and as proposed in the Settlement Agreement filed with the DCPSC, Exelon and PHI currently estimate direct benefits of $430 million or more on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided, including rate credits, funding for energy efficiency programs, sustainability funds and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2017. An additional $50 million will be charged to earnings for charitable contributions, which are required to be paid over a period of 10 years. Commitments to develop renewable generation, which are expected to be primarily capital in nature, will be recognized as incurred. Upon completion of the merger, the actual nature, amount, timing and financial reporting treatment for these commitments may be materially different from the current projection.

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 September 30, 2015, Exelon has incurred approximately $226 million of expense associated with the proposed merger. Of the total costs incurred, $110 million is primarily related to acquisition and integration costs and $116 million is for costs incurred to finance the transaction. The financing costs include a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt; refer to Note 10 — Derivative Financial Instruments and Note 11 — Debt and Credit Agreements for more information. The financing costs exclude costs to issue debt and equity.

During the three months ended September 30, 2015, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs, including financing costs, of $21 million, $9 million, $3 million, $2 million and $2 million, respectively. During the nine months ended September 30, 2015, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs of $47 million, $24 million, $10 million, $4 million and $5 million, respectively.

During the three months ended September 30, 2014, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs, including financing costs, of $32 million, $3 million, $1 million, $1 million and $1 million, respectively. During the nine months ended September 30, 2014, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs of $57 million, $4 million, $1 million,$1 million and $1 million, respectively.

The costs incurred are classified primarily within Operating and maintenance expense in the Registrants’ respective Consolidated Statement of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense.

The Merger Agreement also provides for termination rights for both parties. Exelon and PHI have entered into a Letter Agreement related to the Settlement Agreement which has the practical effect of suspending their rights to terminate the Merger Agreement until November 20, 2015 if no schedule has been set by the DCPSC allowing for approval of the settlement by March 4, 2016, or until March 4, 2016, if a schedule is set for approval by March 4, 2016, but approval does not occur by that date. 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 $180 million (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 reimbursement of PHIs documented out-of-pocket expenses up to a maximum of $40 million.

Merger Financing

As of September 30, 2015, through the issuance of $5.4 billion of debt (including $1.15 billion of junior subordinated notes in the form of 23 million equity units), the issuance of $1.9 billion of common stock, and cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion), Exelon has sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 11 — Debt and Credit Agreements and Note 17 — Common Stock for further information on the debt and equity issuances. See Note 4 — Merger and Acquisitions of the Exelon 2014 Form 10-K for further information on the asset sales.

Asset Divestitures (Exelon and Generation)

On January 21, 2015, Generation closed on 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), including Quail Run and Safe Harbor, which are expected to be used primarily to finance a portion of the acquisition and related costs and expenses of PHI.

On August 8, 2014 Generation closed on the sale of its 67% economic equity interest in the 417 MW Safe Harbor Water Power Corporation hydroelectric facility on the Susquehanna River in Pennsylvania for a purchase price of approximately $615 million. Generation recorded a pre-tax gain on the sale of approximately $329 million within Gain on sales of assets on Exelon’s and Generation’s Consolidated Statements of Operations and Comprehensive Income.

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 September 30, 2015, and December 31, 2014, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $240 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 a 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 ROE 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 ROE 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.

On October 19, 2015, the ALJ issued its proposed order in ComEd's current distribution formula rate proceeding, recommending a total decrease to the revenue requirement of $68 million as compared to ComEd's requested decrease of $50 million discussed above. The $18 million reduction consisted of a $8 million decrease to the initial 2016 revenue requirement and a decrease of $10 million related to the 2014 annual reconciliation. The ALJs proposed order has no independent legal effect as the ICC must vote on a final order by mid December 2015, which may materially vary from the findings and conclusions in the proposed order. If the ICC provides significant changes to ComEd's filed revenue requirement request, it could have a material impact on ComEd's current and future results of operations and cash flows.

Participating utilities are also required to file an annual update on their AMI implementation progress. On April 1, 2015, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC, which allows for the installation of more than 4 million smart meters throughout ComEd's service territory by 2018. To date, over 1.6 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 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 proposals filed by certain landowners to consider an alternate route for a three-mile segment of the transmission line. The rehearing order affirmed the route approved within the ICC's October 22, 2014 order. On July 8, 2015, the ICC approved ComEd's request for eminent domain to involuntarily acquire easements across 28 land parcels. On September 28, 2015, ComEd filed a petition with the ICC to acquire an additional eight parcels through eminent domain. ComEd began construction of the line during 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 requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On October 28, 2015, the ALJ issued a Recommended Decision to the PAPUC that the joint settlement be approved. A final ruling from the PAPUC is expected by December 2015, and if approved, the new electric delivery rates will take effect on January 1, 2016.

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 had 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 included 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 (the Court), claiming that the PAPUC-ordered CAP Shopping plan does not contain sufficient protections for low-income customers. On July 14, 2015, the Court issued opinions on the OCA and low-income advocacy group appeal. Specifically, the Court remanded the issue to the PAPUC with instructions that it approve a rule revision to the PECO CAP Shopping Plan that would prohibit CAP customers from entering into contracts with an EGS that would impose early cancellation/termination fees. PECO does not have information at this time as to what action it may be required to take following remand to the PAPUC.

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. As of September 30, 2015, PECO entered into contracts with PAPUC-approved bidders, including Generation, resulting from the first two of its four scheduled procurements. 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 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. On July 8, 2015, the CAP Design was 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 end 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 primarily funded by SGIG. As of September 30, 2015, PECO has spent $579 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 (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure.

On May 7, 2015, the PAPUC approved PECO's modified natural gas LTIIP. In accordance with the approved LTIIP, PECO plans to spend $534 million through 2022 to further accelerate the replacement of existing gas mains and to relocate 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 LTIIP expenditures. On September 11, 2015, the PAPUC entered its Opinion and Order approving PECO's petition for a gas DSIC.

On March 27, 2015, PECO filed a petition with the PAPUC for approval of its proposed electric DSIC and LTIIP. In accordance with the LTIIP (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. 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. On October 22, 2015, the PAPUC entered its Opinion and Order approving PECO's proposed petition for its electric LTIIP and DSIC.

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 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 funded by SGIG. 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 September 30, 2015 and December 31, 2014, BGE recorded a regulatory asset of $179 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 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 to be effective January 1, 2015 including a true-up of cost estimates included in the 2014 surcharge, along with its 2015 project list and projected capital estimates of $78 million to be included in the 2015 surcharge calculation. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015, which included the true-up of the 2014 charge. As of September 30, 2015, BGE recorded a regulatory liability 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. During the third quarter of 2015, the residential consumer advocate, MDPSC and BGE filed briefs. The Court of Special Appeals has set oral argument in this matter for November 3, 2015. BGE cannot predict the outcome of this appeal. However, if the consumer advocates appeal is successful, BGE could seek recovery of infrastructure replacement costs through other regulatory mechanisms.

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 (NYPSC) 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 NYPSC 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 NYPSC 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. 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. In response to the FERC's April 14, 2015 order, on May 14, 2015, Ginna submitted a compliance filing to FERC containing proposed revisions to the RSSA addressing FERC's requirements and maintaining the April 1, 2015 proposed effective date. On July 13, 2015, FERC accepted Ginna's compliance filing effective April 1, 2015. The FERC accepted Ginna's proposal for market revenue sharing subject to a cap effective April 1, 2015, and rejected requests for rehearing by parties on a number of matters related to jurisdiction, the reliability need, RSSA term, and possible price suppression. In late August, Ginna reached a settlement in principle with interested parties modifying certain terms and conditions in the originally negotiated agreement. The proposed RSSA under the settlement preserves the value of the contract originally negotiated with RG&E, but shortens the term to March 31, 2017 and requires RG&E to complete a new transmission reliability study to determine if an interim reliability solution is required beyond March 31, 2017. The reliability study is expected to be completed by the end of 2015. If there continues to be a reliability need beyond March 31, 2017, RG&E has the right until June 30, 2016 to select Ginna as an ongoing reliability solution. If Ginna is not selected for continued reliability service and does not plan to retire shortly after RSSA expiration, Ginna is required to file a notice with the NYPSC no later than September 30, 2016. The settlement was filed at the NYPSC and at FERC on October 21, 2015 and remains subject to review and approval by both agencies, which do not expect to be completed until the first quarter of 2016.

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 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 September 30, 2015 and December 31, 2014, ComEd had recorded a net regulatory asset associated with the transmission formula rate of $26 million and $21 million, respectively. As of September 30, 2015 and December 31, 2014, BGE recorded a net regulatory asset associated with the transmission formula rate of $5 million and $1 million, 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 (and revised on May 19), ComEd filed its annual transmission formula rate update with the FERC. The filing establishes the revenue requirement used to set rates that took effect in June 2015, subject to review by the FERC and other parties, which is due by fourth quarter 2015. ComEd's 2015 annual update includes a total increase to the revenue requirement of $86 million, reflecting an increase of $68 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 ROE of 11.50%, a decrease from the 8.62% average debt and equity return previously authorized.

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 took effect in June 2015, subject to review by other parties, which is due by October 2015. BGE's 2015 annual update 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 ROE of 11.30%, a decrease from the 8.53% average debt and equity return previously authorized.

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 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 ROE 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 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. On September 14, 2015, the complainants and respondents filed a joint motion to suspend the hearing schedule because they have reached a settlement in principle to resolve the ROE issue. On September 15, 2015, the Chief Administrative Law Judge issued an order granting the motion, and setting October 15, 2015 as the date for the moving parties to either file a settlement or file a status report detailing the timetable for filing a settlement which was subsequently extended to October 30, 2015.

On October 30, 2015, the parties filed a status report stating their intent to either file a settlement or file another status report during the fourth quarter of 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. BGE has established a reserve, which management believes is adequate for what it considers to be the most likely outcome. The estimated annual ongoing reduction in revenues if FERC approves the ROEs as originally requested by the parties in their initial filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% and 8.8% as sought in the first and second complaints, respectively (while retaining the 50 basis points of any incentives that were credited to the base ROE for certain new transmission investment), the result would be a refund to customers of approximately $13 million and $14 million, for the first and second fifteen month refund windows, respectively, for a total refund to customers of approximately $27 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 September 30, 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 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. After the D.C. Circuit denied rehearing in September 2014, the FERC sought to appeal the decision to the U.S. Supreme Court in January 2015. The U.S. Supreme Court agreed to consider the appeal. Oral argument was held at the U.S. Supreme Court on October 14, 2015. A decision is expected to be issued by the U.S. Supreme Court before the end of the term ending on June 30, 2016.

In addition, contemporaneously with the D.C. Circuit Court's decision on May 23, 2014, FirstEnergy filed a complaint at the FERC asking the 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 the 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 the FERC asking the 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. The 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 depending on how the U.S. Supreme Court resolves the matter. In addition, there is uncertainty as to how the FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation resources, again depending on the U.S. Supreme Court resolution. 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 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 31, 2019 delivery period). On June 18, 2015, the FERC accepted the results of the ninth capacity auction. On July 20, 2015, a union representing utility workers sought rehearing of that decision. While it is unlikely that the FERC would alter its decision on rehearing, Exelon and Generation cannot predict with certainty what future actions the FERC may take concerning the results of the auction. Adverse action by the FERC could ultimately be material to Exelon's and Generation's expected revenues from the auction.

On February 28, 2014, ISO-NE filed the results of its eighth capacity auction (covering the June 1, 2017 through May 31, 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. On August 7, 2015, US Fish and Wildlife Service (USFWS) submitted its modified fishway prescription to FERC in the Conowingo licensing proceedings. On September 11, 2015, Exelon filed a request for an administrative hearing and proposed an alternative prescription to challenge USFWS's preliminary prescription. 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.

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

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 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.

The stations are currently being depreciated over their estimated useful lives, which includes the license renewal period. As of September 30, 2015, $43 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 September 30, 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.

September 30, 2015	Exelon	ComEd	PECO	BGE
Regulatory assets				
Pension and other postretirement benefits	$3,138	$ —	$ —	$ —
Deferred income taxes	1,589	66	1,446	77
AMI programs	373	130	64	179
Under-recovered distribution service costs[a]	240	240	—	—
Debt costs	50	48	2	8
Fair value of BGE long-term debt	170	—	—	—
Severance	10	—	—	10
Asset retirement obligations	106	66	22	18
MGP remediation costs[g]	289	256	32	1
Under-recovered uncollectible accounts	54	54	—	—
Renewable energy	243	243	—	—
Energy and transmission programs[b][c]	67	33	—	34
Deferred storm costs[g]	2	—	—	2
Electric generation-related regulatory asset[g]	23	—	—	23
Rate stabilization deferral	101	—	—	101
Energy efficiency and demand response programs	271	—	—	271
Merger integration costs	6	—	—	6
Conservation voltage reduction	1	—	—	1

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

September 30, 2015	Exelon	ComEd	PECO	BGE
Under-recovered revenue decoupling[f]	7	—	—	7
Other	39	9	23	4
Total regulatory assets	6,779	1,145	1,589	742
Less: current portion	779	232	32	257
Total noncurrent regulatory assets	$6,000	$ 913	$1,557	$485

September 30, 2015	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 65	$ —	$ —	$ —
Nuclear decommissioning	2,538	2,150	388	—
Removal costs	1,545	1,342	—	203
Energy efficiency and demand response programs[d]	46	44	2	—
DLC Program Costs	9	—	9	—
Energy efficiency phase II	38	—	38	—
Electric distribution tax repairs	97	—	97	—
Gas distribution tax repairs	30	—	30	—
Energy and transmission programs[b][c][e]	134	46	70	18
Over-recovered electric universal service fund costs	3	—	3	—
Over-recovered revenue decoupling[f]	27	—	—	27
Other	13	3	3	7
Total regulatory liabilities	4,545	3,585	640	255
Less: current portion	365	144	104	69
Total noncurrent regulatory liabilities	$4,180	$3,441	$536	$186

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory assets				
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[a]	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[b][c]	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[f]	7	—	—	7
Other	46	22	14	7
Total regulatory assets	6,923	1,201	1,558	724
Less: current portion	847	349	29	214
Total noncurrent regulatory assets	$6,076	$ 852	$1,529	$510

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

December 31, 2014	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 88	$ —	$ —	$ —
Nuclear decommissioning	2,879	2,389	490	—
Removal costs	1,566	1,343	—	223
Energy efficiency and demand response programs(d)	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(b)(c)(e)	84	19	58	7
Over-recovered electric universal service fund costs	2	—	2	—
Revenue subject to refund	3	3	—	—
Over-recovered revenue decoupling(f)	12	—	—	12
Other	6	1	2	2
Total regulatory liabilities	4,860	3,780	747	244
Less: current portion	310	125	90	44
Total noncurrent regulatory liabilities	$4,550	$3,655	$657	$200

(a) As of September 30, 2015, ComEd's regulatory asset of $240 million was comprised of $184 million for the applicable annual reconciliations and $56 million related to significant one-time events including $43 million of deferred storm costs and $13 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 September 30, 2015, ComEd's regulatory asset of $33 million included $26 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 September 30, 2015, ComEd's regulatory liability of $46 million included $24 million related to over-recovered energy costs for hourly customers and $22 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 September 30, 2015, BGE's regulatory asset of $34 million included $5 million associated with transmission costs recoverable through its FERC approved formula rate and $29 million related to under-recovered electric energy costs. As of September 30, 2015, BGE's regulatory liability of $18 million related to $9 million of over-recovered natural gas supply costs and $14 million of over-recovered energy costs, offset by $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 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) ComEd recovers the costs of its ICC-approved Energy Efficiency and Demand Response plan through a rider. Effective with a change to its rider in August 2015, ComEd will recover or refund any under or over-recoveries through the end of the Plan's fiscal year on May 31 over a twelve-month period beginning on June 1 of the following calendar year. Previously, ComEd's recovery or refund of under or over-recoveries through the end of the Plan's fiscal year on May 31 was over a nine-month period beginning on September 1 of the same calendar year.

(e) As of September 30, 2015, PECO's regulatory liability of $70 million included $33 million related to the DSP program, $31 million related to the over-recovered natural gas costs under the PGC and $6 million related to over-recovered electric transmission costs. As of December 31, 2014, PECO's regulatory liability of $58 million included $39 million related to the DSP program, $16 million related to the over-recovered natural gas costs under the PGC and $3 million related to the over-recovered electric transmission costs.

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

(f) Represents the electric and gas distribution costs recoverable from customers under BGE's decoupling mechanism. As of September 30, 2015, BGE had a regulatory asset of $7 million related to under-recovered electric revenue decoupling and a regulatory liability of $27 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.
(g) In accordance with the MDPSC approved 2014 electric and natural gas distribution rate case orders, the recovery periods for these regulatory assets were revised, effective in January 2015.

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 September 30, 2015 and December 31, 2014.

As of September 30, 2015	Exelon	ComEd	PECO	BGE
Purchased receivables[(a)]	$ 296	$ 137	$ 90	$ 69
Allowance for uncollectible accounts[(b)]	(40)	(22)	(8)	(10)
Purchased receivables, net	$ 256	$ 115	$ 82	$ 59

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

(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. The implementation costs were fully recovered and the 1% discount was reset to 0%, effective July 2015.
(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 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%, respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs through December 31, 2014. 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, CENG's sales to Generation have been eliminated in consolidation. For the three and nine months ended September 30, 2015, Generation had sales to EDF of $108 million and $395 million, respectively. See Note 3 — Variable Interest Entities for additional information regarding other transactions between CENG and EDF included within Exelon's and Generation's consolidated financial statements and for additional information about the Registrant's VIEs.

Accounting for the Consolidation of CENG

Prior to April 1, 2014, Exelon and Generation accounted for their investment in CENG under the equity method of accounting. From January 1, 2014, through 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 Consolidated 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 considers Generation's Preferred Distribution Rights and allocates net income based on each owner's rights to CENG's net assets. For the three and nine months ended September 30, 2015, Generation reduced by $5 million and $13 million, respectively, 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 $110 million and $416 million and CENG's net income (loss), prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $(75) million and $18 million during the three and nine months ended September 30, 2015, respectively.

7. Impairment of Long-Lived Assets (Exelon and Generation)

Long-Lived Assets (Exelon and Generation)

Generation evaluates long-lived assets for recoverability whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. In the second quarter of each year, Generation updates the long-term fundamental energy prices, which includes a thorough evaluation of key assumptions including gas prices, load growth, environmental policy, plant retirements and renewable growth.

In 2015, the year over year change in fundamentals did not indicate any impairments. In 2014, the year over year change in fundamentals suggested that the carrying value of certain merchant wind assets may be impaired. Generation concluded that the estimated undiscounted future cash flows and fair value of twelve wind projects, primarily located in West Texas, were less than their respective carrying values at May 31, 2014. As a result, long-lived assets held and used with a carrying amount of approximately $151 million were written down to their fair value of $65 million and a pre-tax impairment charge of $86 million was recorded during the second quarter of 2014 in Operating and maintenance expense in Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

The fair value analysis was primarily based on the income approach using significant unobservable inputs (Level 3) including revenue and generation forecasts, projected capital and maintenance expenditures and discount rates. Changes in the assumptions described above could potentially result in future impairments of Exelon's long-lived assets, which could be material.

During the third quarter of 2014, certain non-nuclear generating assets were identified as assets held for sale on Exelon's and Generation's Consolidated Balance Sheets. When long-lived assets are held for sale, an impairment loss is recognized to the extent that the asset's carrying value exceeds its estimated fair value less costs to sell. At September 30, 2014, in connection with the approved asset sales agreements, a $50 million pre-tax impairment loss was recorded within Operating and maintenance expense on Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Like-Kind Exchange Transaction (Exelon)

Prior to the PECO/Unicom Merger in October 2000, UII, LLC (formerly Unicom Investments, Inc.) (UII), a wholly owned subsidiary of Exelon, entered into a like-kind exchange transaction pursuant to which approximately $1.6 billion was invested in coal-fired generating station leases located in Georgia and Texas with two separate entities unrelated to Exelon. The generating stations were leased back to such entities as part of the transaction. See Note 12 — Income Taxes for further information. The leases for the generating stations located in Texas were terminated in 2014. For financial accounting purposes, the investments are accounted for as direct financing lease investments. UII holds the leasehold interests in the generating stations in several separate bankruptcy remote, special purpose companies it directly or indirectly wholly owns. The lease agreements provide the lessees with fixed purchase options at the end of the lease terms. If the lessees do not exercise the fixed purchase options, Exelon has the ability to operate the stations and keep or market the power itself or require the lessees to arrange for a third-party to bid on a service contract for a period following the lease term. In any event, Exelon will be subject to residual value risk if the lessees do 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. In the fourth quarter of 2000, under the terms of the lease agreements, UII received a prepayment of $1.2 billion for all rent, which reduced the investment in the leases. There are no minimum scheduled lease payments to be received over the remaining term of the leases.

Pursuant to the applicable accounting guidance, Exelon is required to review the estimated residual values of its direct financing lease investments at least annually and record an impairment charge if the review indicates an other than temporary decline in the fair value of the residual values below their carrying values. Exelon estimates the fair value of the residual values of its direct financing lease investments under the income approach, which uses a discounted cash flow analysis, which takes into consideration significant unobservable inputs (Level 3) including the expected revenues to be generated and costs to be incurred to operate the plants over their remaining useful lives subsequent to the lease end dates. Significant assumptions used in estimating the fair value include fundamental energy and capacity prices, fixed and variable costs, capital expenditure requirements, discount rates, tax rates, and the estimated remaining useful lives of the plants. The estimated fair values also reflect the cash flows associated with the service contract option discussed above given that a market participant would take into consideration all of the terms and conditions contained in the lease agreements.

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

Based on the annual reviews performed in the second quarters of 2015 and 2014, the estimated residual value of Exelon's direct financing leases for the Georgia generating stations experienced other than temporary declines given increases in estimated long-term operating and maintenance costs in the 2015 annual review and reduced long-term energy and capacity price expectations in the 2014 annual review. As a result, Exelon recorded $24 million pre-tax impairment charges in each of the second quarters of 2015 and 2014 for these stations. These impairment charges were recorded in Investments and Operating and maintenance expense in Exelon's Consolidated Balance Sheets and the Consolidated Statements of Operations and Comprehensive Income, respectively. Changes in the assumptions described above could potentially result in future impairments of Exelon's direct financing lease investments, which could be material.

At September 30, 2015 and December 31, 2014, the components of the net investment in long-term leases were as follows:

	September 30, 2015	December 31, 2014
Estimated residual value of leased assets	$ 639	$ 685
Less: unearned income	291	324
Net investment in long-term leases	$ 348	$ 361

8. Implications of Potential Early Plant Retirements (Exelon and Generation)

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative solutions in Illinois such as the proposed Low Carbon Portfolio Standard (LCPS) legislation, the impact of final rules from the U.S. EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules, and the outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions. On September 10, 2015, after considering the results of the recent PJM capacity auctions, Exelon and Generation decided to defer for one year any decisions about the future operations of its Quad Cities and Byron nuclear plants and will offer both plants in the 2019/2020 auction in May 2016. As a result of clearing the other PJM capacity auction in September 2015 for the 2017/2018 transitional capacity auction, Exelon and Generation will continue to operate its Quad Cities nuclear power plant through at least May 2018. The Byron plant is already obligated to operate through May 2019. In addition, on October 29, 2015, Exelon and Generation decided to defer any decision about the future operations of its Clinton nuclear plant for one year and plan to bid the plant into the MISO capacity auction for the 2016/2017 planning year in March 2016. MISO's announcement on October 27, 2015 acknowledging the need for market design changes in southern Illinois was a key factor in Exelon's and Generation's decision to defer for an additional year, among other factors such as positive results from the Illinois Power Agency's capacity procurement for 2016 and the long-term impact of the EPA's Clean Power Plan. The Clinton plant is currently obligated to operate through May 2016. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. Exelon and Generation have not made any decisions regarding potential nuclear plant closures at other sites at this time.

As a result of a decision to early retire one or more other nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by a number of items including, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of decommissioning costs. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown. While there are a number of Generation's nuclear plants that are at risk of early retirement, the following table provides the balance sheet amounts as of September 30, 2015 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to their current economic valuations and other factors:

(in millions)	Quad Cities	Clinton	Ginna	Total
Asset Balances				
Materials and supplies inventory	$ 49	$ 56	$ 30	$ 135
Nuclear fuel inventory, net	186	122	65	373
Completed plant, net	1,027	582	111	1,720
Construction work in progress	29	8	23	60
Liability Balances				
Asset retirement obligation	(696)	(396)	(637)	(1,729)
NRC License Renewal Term	2032	2046[(a)]	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

In the event a decision is made to early retire one or more nuclear plants, the precise timing of the retirement date, and resulting financial statement impact, is uncertain and would be influenced by a number of factors such as the results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations and just prior to its next scheduled nuclear refueling outage date in that year.

9. 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 September 30, 2015 and December 31, 2014:

Exelon

	September 30, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 678	$ 3	$ 675	$ —	$ 678
Long-term debt (including amounts due within one year)	25,438	1,004	24,181	1,335	26,520
Long-term debt to financing trusts	648	—	—	663	663
SNF obligation	1,021	—	820	—	820

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

	December 31, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
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

	September 30, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 21	$ —	$ 21	$ —	$ 21
Long-term debt (including amounts due within one year)	8,996	—	7,978	1,335	9,313
SNF obligation	1,021	—	820	—	820

	December 31, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
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

	September 30, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 604	$ —	$ 604	$ —	$ 604
Long-term debt (including amounts due within one year)	6,100	—	6,731	—	6,731
Long-term debt to financing trust	206	—	—	206	206

	December 31, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
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	206	—	—	213	213

PECO

	September 30, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,246	$ —	$2,472	$ —	$2,472
Long-term debt to financing trusts	184	—	—	196	196

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

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

BGE

	September 30, 2015				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 53	$ 3	$ 50	$ —	$ 53
Long-term debt (including amounts due within one year)	1,905	—	2,118	—	2,118
Long-term debt to financing trusts	258	—	—	261	261

	December 31, 2014				
	Carrying Amount	Fair Value			
		Level 1	Level 2	Level 3	Total
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 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). Generation also has tax-exempt debt (Level 2). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (e.g., conduit issuer political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

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

Long-Term Debt to Financing Trusts. 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 liquidate 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 no transfers between Level 1 and Level 2 during the nine months ended September 30, 2015 for cash equivalents, nuclear decommissioning trust fund investments, pledged assets for Zion Station decommissioning, Rabbi trust investments, and deferred compensation obligations.

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

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 September 30, 2015 and December 31, 2014:

	Generation				Exelon			
As of September 30, 2015	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets								
Cash equivalents[(a)]	$ 225	$ —	$ —	$ 225	$ 6,545	$ —	$ —	$ 6,545
Nuclear decommissioning trust fund investments								
Cash equivalents	301	67	—	368	301	67	—	368
Equity								
Domestic	2,274	1,829	—	4,103	2,274	1,829	—	4,103
Foreign	598	—	—	598	598	—	—	598
Equity funds subtotal	2,872	1,829	—	4,701	2,872	1,829	—	4,701
Fixed income								
Corporate debt	—	1,831	245	2,076	—	1,831	245	2,076
U.S. Treasury and agencies	1,142	—	—	1,142	1,142	—	—	1,142
Foreign governments	—	77	—	77	—	77	—	77
State and municipal debt	—	407	—	407	—	407	—	407
Other	—	468	—	468	—	468	—	468
Fixed income subtotal	1,142	2,783	245	4,170	1,142	2,783	245	4,170
Middle market lending	—	—	423	423	—	—	423	423
Private equity	—	—	116	116	—	—	116	116
Real estate	—	—	30	30	—	—	30	30
Other	—	329	—	329	—	329	—	329
Nuclear decommissioning trust fund investments subtotal[(b)]	4,315	5,008	814	10,137	4,315	5,008	814	10,137
Pledged assets for Zion Station decommissioning								
Cash equivalents	—	11	—	11	—	11	—	11
Equities	5	1	—	6	5	1	—	6
Fixed income								
U.S. Treasury and agencies	5	2	—	7	5	2	—	7
Corporate debt	—	57	—	57	—	57	—	57
State and municipal debt	—	10	—	10	—	10	—	10
Other	—	1	—	1	—	1	—	1
Fixed income subtotal	5	70	—	75	5	70	—	75
Middle market lending	—	—	144	144	—	—	144	144
Pledged assets for Zion Station decommissioning subtotal[(c)]	10	82	144	236	10	82	144	236
Rabbi trust investments in mutual funds[(d)(e)]	16	—	—	16	46	—	—	46
Commodity derivative assets								
Economic hedges	1,625	2,561	2,144	6,330	1,625	2,561	2,144	6,330
Proprietary trading	85	140	38	263	85	140	38	263
Effect of netting and allocation of collateral[(f)]	(1,865)	(2,037)	(835)	(4,737)	(1,865)	(2,037)	(835)	(4,737)
Commodity derivative assets subtotal	(155)	664	1,347	1,856	(155)	664	1,347	1,856
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments	—	—	—	—	—	37	—	37
Economic hedges	—	21	—	21	—	21	—	21
Proprietary trading	14	3	—	17	14	3	—	17
Effect of netting and allocation of collateral	(8)	(6)	—	(14)	(8)	(6)	—	(14)
Interest rate and foreign currency derivative assets subtotal	6	18	—	24	6	55	—	61

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

	Generation				Exelon			
As of September 30, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Other investments	—	—	32	32	—	—	32	32
Total assets	4,417	5,772	2,337	12,526	10,767	5,809	2,337	18,913
Liabilities								
Commodity derivative liabilities								
Economic hedges	(2,120)	(2,478)	(1,209)	(5,807)	(2,120)	(2,478)	(1,452)	(6,050)
Proprietary trading	(79)	(140)	(44)	(263)	(79)	(140)	(44)	(263)
Effect of netting and allocation of collateral[f]	2,218	2,472	1,080	5,770	2,218	2,472	1,080	5,770
Commodity derivative liabilities subtotal	19	(146)	(173)	(300)	19	(146)	(416)	(543)
Interest rate and foreign currency derivative liabilities								
Derivatives designated as hedging instruments	—	(21)	—	(21)	—	(21)	—	(21)
Economic hedges	—	(6)	—	(6)	—	(6)	—	(6)
Proprietary trading	(15)	—	—	(15)	(15)	—	—	(15)
Effect of netting and allocation of collateral	15	6	—	21	15	6	—	21
Interest rate and foreign currency derivative liabilities subtotal	—	(21)	—	(21)	—	(21)	—	(21)
Deferred compensation obligation	—	(29)	—	(29)	—	(95)	—	(95)
Total liabilities	19	(196)	(173)	(350)	19	(262)	(416)	(659)
Total net assets	$ 4,436	$ 5,576	$ 2,164	$12,176	$10,786	$ 5,547	$ 1,921	$18,254

	Generation				Exelon			
As of December 31, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[a]	$ 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	—	—	366	366	—	—	366	366
Private equity	—	—	83	83	—	—	83	83
Real estate	—	—	3	3	—	—	3	3
Other	—	301	—	301	—	301	—	301
Nuclear decommissioning trust fund investments subtotal[b]	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

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

	Generation				Exelon			
As of December 31, 2014	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Pledged assets for Zion Station decommissioning subtotal[c]	11	121	184	316	11	121	184	316
Rabbi trust investments[d]								
Cash equivalents	—	—	—	—	1	—	—	1
Mutual funds[e]	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[f]	(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
Interest rate and foreign currency derivative assets								
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
Total assets	4,558	6,742	2,029	13,329	5,305	6,747	2,029	14,081
Liabilities								
Commodity derivative liabilities								
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[f]	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)
Interest rate and foreign currency derivative liabilities								
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)
Total liabilities	(9)	(240)	(101)	(350)	(9)	(427)	(308)	(744)
Total net assets	$ 4,549	$ 6,502	$ 1,928	$12,979	$ 5,296	$ 6,320	$ 1,721	$13,337

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

(b) Excludes net liabilities of $(34) million and $(5) million at September 30, 2015 and December 31, 2014, respectively. These items consist of net 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 September 30, 2015 and December 31, 2014, respectively. These items consist of net receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) Excludes $34 million and $35 million of cash surrender value of life insurance investment at September 30, 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 September 30, 2015 and December 31, 2014, respectively, at Generation.

(e) The mutual funds held by the Rabbi trusts at Exelon include $45 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at September 30, 2015, and $45 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2014.

(f) Collateral posted to/(received from) counterparties totaled $353 million, $435 million and $245 million allocated to Level 1, Level 2 and Level 3 commodity mark-to-market derivatives, respectively, as of September 30, 2015. Collateral posted to/(received from) counterparties totaled $434 million, $800 million and $172 million allocated to Level 1, Level 2 and Level 3 commodity mark-to-market derivatives, respectively, as of December 31, 2014.

(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 September 30, 2015 and December 31, 2014:

	ComEd				PECO				BGE			
As of September 30, 2015	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets												
Cash equivalents	$ —	$ —	$ —	$ —	$ 4	$ —	$ —	$ 4	$ 68	$ —	$ —	$ 68
Rabbi trust investments in mutual funds[(a)]	—	—	—	—	8	—	—	8	5	—	—	5
Total assets	—	—	—	—	12	—	—	12	73	—	—	73
Liabilities												
Deferred compensation obligation	—	(7)	—	(7)	—	(11)	—	(11)	—	(4)	—	(4)
Mark-to-market derivative liabilities[(b)]	—	—	(243)	(243)	—	—	—	—	—	—	—	—
Total liabilities	—	(7)	(243)	(250)	—	(11)	—	(11)	—	(4)	—	(4)
Total net assets (liabilities)	$ —	$ (7)	$(243)	$(250)	$ 12	$ (11)	$ —	$ 1	$ 73	$ (4)	$ —	$ 69

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

(a) At PECO, excludes $12 million and $14 million of the cash surrender value of life insurance investments at September 30, 2015 and December 31, 2014, respectively.

(b) The Level 3 balance includes the current and noncurrent liability of $22 million and $221 million at September 30, 2015, respectively, and $20 million and $187 million at December 31, 2014, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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 and nine months ended September 30, 2015 and 2014:

	Generation					ComEd		Exelon
Three Months Ended September 30, 2015	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives[b]	Eliminated in Consolidation	Total
Balance as of June 30, 2015	$ 786	$ 156	$ 1,021	$ 30	$ 1,993	$ (223)	$ —	$ 1,770
Total realized / unrealized gains (losses)								
Included in net income	—	—	(48)[a]	—	(48)	—	—	(48)
Included in noncurrent payables to affiliates	5	—	—	—	5	—	(5)	—
Included in payable for Zion Station decommissioning	—	1	—	—	1	—	—	1
Included in regulatory assets	—	—	—	—	—	(20)	5	(15)
Change in collateral	—	—	90	—	90	—	—	90
Purchases, sales, issuances and settlements								
Purchases	40	5	50	2	97	—	—	97
Sales	—	(18)	(5)	—	(23)	—	—	(23)
Settlements	(17)	—	—	—	(17)	—	—	(17)
Transfers into Level 3	—	—	69	—	69	—	—	69
Transfers out of Level 3	—	—	(3)	—	(3)	—	—	(3)
Balance as of September 30, 2015	$ 814	$ 144	$ 1,174	$ 32	$ 2,164	$ (243)	$ —	$ 1,921
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 three months ended September 30, 2015	$ (1)	$ —	$ 181	$ —	$ 180	$ —	$ —	$ 180

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

Nine Months Ended September 30, 2015	Generation: Nuclear Decommissioning Trust Fund Investments	Generation: Pledged Assets for Zion Station Decommissioning	Generation: Mark-to-Market Derivatives	Generation: Other Investments	Generation: Total Generation	ComEd: Mark-to-Market Derivatives[b]	Eliminated in Consolidation	Exelon: Total
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	4	—	(87)[a]	—	(83)	—	—	(83)
Included in noncurrent payables to affiliates	20	—	—	—	20	—	(20)	—
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	2
Included in regulatory assets	—	—	—	—	—	(36)	20	(16)
Change in collateral	—	—	72	—	72	—	—	72
Purchases, sales, issuances and settlements								
Purchases	186	16	107	29	338	—	—	338
Sales	(8)	(58)	(10)	—	(76)	—	—	(76)
Settlements	(83)	—	—	—	(83)	—	—	(83)
Transfers into Level 3	4	—	80	—	84	—	—	84
Transfers out of Level 3	—	—	(38)	—	(38)	—	—	(38)
Balance as of September 30, 2015	$ 814	$ 144	$ 1,174	$ 32	$ 2,164	$ (243)	$ —	$ 1,921
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the nine months ended September 30, 2015	$ 4	$ —	$ 536	$ —	$ 540	$ —	$ —	$ 540

(a) Includes a reduction for the reclassification of $229 million and $623 million of realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2015, respectively.

(b) Includes $19 million of decreases in fair value and a reduction for realized gains due to settlements of $1 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2015. Includes $44 million of decreases in fair value and an increase for realized losses due to settlements of $8 million for the nine months ended September 30, 2015.

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

Three Months Ended September 30, 2014	Generation: Nuclear Decommissioning Trust Fund Investments	Generation: Pledged Assets for Zion Station Decommissioning	Generation: Mark-to-Market Derivatives	Generation: Other Investments	Generation: Total Generation	ComEd: Mark-to-Market Derivatives[b]	Eliminated in Consolidation	Exelon: Total
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977	$ (134)	$ —	$ 843
Total realized / unrealized gains (losses)								
Included in net income	1	—	76[a]	—	77	—	—	77
Included in noncurrent payables to affiliates	3	—	—	—	3	—	(3)	—
Included in payable for Zion Station decommissioning	—	(2)	—	—	(2)	—	—	(2)
Included in regulatory assets	—	—	—	—	—	(44)	3	(41)
Change in collateral	—	—	79	—	79	—	—	79
Purchases, sales, issuances and settlements								
Purchases	83	53	12	—	148	—	—	148
Sales	(8)	(18)	—	(7)	(33)	—	—	(33)
Settlements	(27)	—	—	—	(27)	—	—	(27)
Transfers into Level 3	—	—	21	—	21	—	—	21
Transfers out of Level 3	—	—	1	—	1	—	—	1
Balance as of September 30, 2014	$ 644	$ 166	$ 431	$ 3	$ 1,244	$ (178)	$ —	$ 1,066
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 September 30, 2014	$ 1	$ —	$ 163	$ —	$ 164	$ —	$ —	$ 164

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

	Generation					ComEd		Exelon
Nine Months Ended September 30, 2014	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total Generation	Mark-to-Market Derivatives[b]	Eliminated in Consolidation	Total
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942	$ (193)	$ —	$ 749
Total realized / unrealized gains (losses)								
Included in net income	5	—	(284)[a]	—	(279)	—	—	$ (279)
Included in noncurrent payables to affiliates	14	—	—	—	14	—	(14)	$ —
Included in payable for Zion Station decommissioning	—	2	—	—	2	—	—	$ 2
Included in regulatory assets	—	—	—	—	—	15	14	$ 29
Change in collateral	—	—	257	—	257	—	—	$ 257
Purchases, sales, issuances and settlements								
Purchases	331	95	27	2	455	—	—	$ 455
Sales	(10)	(43)	(6)	(7)	(66)	—	—	$ (66)
Settlements	(46)	—	—	—	(46)	—	—	$ (46)
Transfers into Level 3	—	—	(9)	—	(9)	—	—	$ (9)
Transfers out of Level 3	—	—	(19)	(7)	(26)	—	—	$ (26)
Balance as of September 30, 2014	$ 644	$ 166	$ 431	$ 3	$ 1,244	$ (178)	$ —	$ 1,066
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 September 30, 2014	$ 3	$ —	$ (264)	$ —	$ (261)	$ —	$ —	$ (261)

(a) Includes a reduction for the reclassification of $87 million and $20 million of realized gains due to the settlement of derivative contracts for the three and nine months ended September 30, 2014.

(b) Includes $45 million of decreases in fair value and an increase for realized losses due to settlements of $1 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended September 30, 2014. Includes $19 million of increases in fair value and a reduction for realized gains due to settlements of $4 million for the nine months ended September 30, 2014.

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 and nine months ended September 30, 2015 and 2014:

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended September 30, 2015	$ (4)	$ (44)	$ —	$ (4)	$ (44)	$ —
Total gains (losses) included in net income for the nine months ended September 30, 2015	(31)	(56)	4	(31)	(56)	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2015	198	(17)	(1)	198	(17)	(1)
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2015	538	(2)	4	538	(2)	4

	Generation			Exelon		
	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]	Operating Revenues	Purchased Power and Fuel	Other, net[(a)]
Total gains (losses) included in net income for the three months ended September 30, 2014	$ 70	$ 6	$ 1	$ 70	$ 6	$ 1
Total gains (losses) included in net income for the nine months ended September 30, 2014	(260)	(24)	5	(260)	(24)	5
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended September 30, 2014	142	21	1	142	21	1
Change in the unrealized gains (losses) relating to assets and liabilities held for the nine months ended September 30, 2014	(293)	29	3	(293)	29	3

(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 NDT fund investments policies outline investment guidelines for the trusts and 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.

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 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 lend to 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 September 30, 2015, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $286 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 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 10 — 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 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 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. 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 and certain transmission congestion contracts. 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 $3.30 and $0.32 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.

(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 10 —Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk.

The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at September 30, 2015	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic hedges (Generation)[a][c]	$ 935	Discounted Cash Flow	Forward power price	$11 - $96[d]
			Forward gas price	$1.49 - $9.86[d]
		Option Model	Volatility percentage	7% - 130%
Mark-to-market derivatives — Proprietary trading (Generation)[a][c]	$ (6)	Discounted Cash Flow	Forward power price	$13 - $89[d]
Mark-to-market derivatives (ComEd)	$ (243)	Discounted Cash Flow	Forward heat rate[b]	9x - 10x
			Marketability reserve	3.5% - 7%
			Renewable factor	85% - 126%

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

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

(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 posted on level three positions of $245 million as of September 30, 2015.
(d) The New England region was not a significant driver for the upper end of the ranges for power and gas as of September 30, 2015.

Type of trade	Fair Value at December 31, 2014	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives — Economic hedges (Generation)(a)(c)	$ 893	Discounted Cash Flow	Forward power price	$15 - $120(d)
			Forward gas price	$1.52 - $14.02(d)
		Option Model	Volatility percentage	8% - 257%
Mark-to-market derivatives — Proprietary trading (Generation)(a)(c)	$ (15)	Discounted Cash Flow	Forward power price	$15 - $117(d)
Mark-to-market derivatives (ComEd)	$ (207)	Discounted Cash Flow	Forward heat rate(b)	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 posted 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.

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.

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

The Registrants use derivative instruments to manage commodity price risk, foreign currency exchange rate 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 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 September 30, 2015, the proportion of expected generation hedged for the major reportable segments was 97%-100%, 81%-84%, and 51%-54% 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.

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 2015 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 2015 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 1,913 GWhs and 5,378 GWhs for the three and nine months ended September 30, 2015, respectively, and 3,006 GWhs and 8,129 GWhs for the three and nine months ended September 30, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
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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 strategies are employed to manage interest rate risks. At September 30, 2015, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $752 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper) and fixed-to-floating swaps would result in an approximately $3 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 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 September 30, 2015.

	Generation					Other				Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting[(b)]	Subtotal	Total
Mark-to-market derivative assets (current assets)	$ —	$ 11	$ 10	$ (12)	$ 9	$ —	$ —	$ —	$ —	$ 9
Mark-to-market derivative assets (noncurrent assets)	—	10	7	(2)	15	37	—	—	37	52
Total mark-to-market derivative assets	—	21	17	(14)	24	37	—	—	37	61
Mark-to-market derivative liabilities (current liabilities)	(9)	(6)	(10)	16	(9)	—	—	—	—	(9)
Mark-to-market derivative liabilities (noncurrent liabilities)	(12)	—	(5)	5	(12)	—	—	—	—	(12)
Total mark-to-market derivative liabilities	(21)	(6)	(15)	21	(21)	—	—	—	—	(21)
Total mark-to-market derivative net assets (liabilities)	$ (21)	$ 15	$ 2	$ 7	$ 3	$ 37	$ —	$ —	$ 37	$ 40

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

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(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.

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

	Generation					Other				Exelon
Description	Derivatives Designated as Hedging Instruments	Economic Hedges	Proprietary Trading[(a)]	Collateral and Netting[(b)]	Subtotal	Derivatives Designated as Hedging Instruments	Economic Hedges	Collateral and Netting[(b)]	Subtotal	Total
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
Total mark-to-market derivative assets	8	12	27	(29)	18	23	1	(19)	5	23
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)
Total mark-to-market derivative liabilities	(12)	(2)	(23)	35	(2)	(29)	(101)	19	(111)	(113)
Total mark-to-market derivative net assets (liabilities)	$ (4)	$ 10	$ 4	$ 6	$ 16	$ (6)	$ (100)	$ —	$ (106)	$ (90)

(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.

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

(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.

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 September 30,			
		2015	2014	2015	2014
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense[(a)]	$ —	$ (4)	$ —	$ 1
Exelon	Interest expense	16	(8)	13	(6)

	Income Statement Location	Nine Months Ended September 30,			
		2015	2014	2015	2014
		Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense[(a)]	$ (1)	$ (12)	$ —	$ 1
Exelon	Interest expense	13	(3)	8	6

(a) For the three and nine months ended September 30, 2015, the loss on Generation swaps included $0 million and $1 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing. For the three and nine months ended September 30, 2014, the loss on Generation swaps included $4 million and $12 million realized in earnings, respectively, with an $2 million amount excluded from hedge effectiveness testing.

At September 30, 2015, Exelon had total outstanding fixed-to-floating fair value hedges related to interest rate swaps of $800 million, with a derivative asset of $37 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 and nine months ended September 30, 2015, the impact on the results of operations as a result of the ineffectiveness from fair value hedges was a $3 million and $11 million gain, respectively. During the three and nine months ended September 30, 2014, the impact on the results of operations as a result of the ineffectiveness from fair value hedges was a $6 million and $14 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 $501 million as of September 30, 2015 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At September 30, 2015, the subsidiary had a $16 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 $200 million as of September 30, 2015 and expire in 2020. The swaps are designated as cash flow hedges. At September 30, 2015, the subsidiary had a $4 million derivative liability related to the swaps.

During the three and nine months ended September 30, 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 September 30, 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. All future changes in fair value are reflected in Interest expense. At September 30, 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 $25 million as of September 30, 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. All future changes in fair value are reflected in Interest expense. At September 30, 2015, the subsidiary had an immaterial derivative liability related to the swap.

During the second quarter 2015, upon the issuance of debt, Exelon terminated $2,400 million of floating-to-fixed forward starting interest rate swaps. As a result of the termination of the swaps, Exelon realized a $64 million loss during the second quarter of 2015.

At September 30, 2015, Generation had immaterial notional amounts of interest rate derivative contracts to economically hedge risk associated with the interest rate component of commodity positions and $99 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 September 30, 2015 and December 31, 2014, $4 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.

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

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

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 September 30, 2015:

	Generation				ComEd	Exelon
Derivatives	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)]	Subtotal[(b)]	Economic Hedges[(c)]	Total Derivatives
Mark-to-market derivative assets (current assets)	$ 3,958	$ 221	$ (3,072)	$ 1,107	$ —	$ 1,107
Mark-to-market derivative assets (noncurrent assets)	2,372	42	(1,665)	749	—	749
Total mark-to-market derivative assets	6,330	263	(4,737)	1,856	—	1,856
Mark-to-market derivative liabilities (current liabilities)	(3,719)	(213)	3,759	(173)	(22)	(195)
Mark-to-market derivative liabilities (noncurrent liabilities)	(2,088)	(50)	2,011	(127)	(221)	(348)
Total mark-to-market derivative liabilities	(5,807)	(263)	5,770	(300)	(243)	(543)
Total mark-to-market derivative net assets (liabilities)	$ 523	$ —	$ 1,033	$ 1,556	$ (243)	$ 1,313

(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 $281 million and $150 million, respectively, and current and noncurrent liabilities are shown net of collateral of $405 million and $197 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $1,033 million at September 30, 2015.

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

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

	Generation				ComEd	Exelon
Description	Economic Hedges	Proprietary Trading	Collateral and Netting[(a)]	Subtotal[(b)]	Economic Hedges[(c)]	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
Total mark-to-market derivative assets	6,813	512	(5,296)	2,029	—	2,029
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)
Total mark-to-market derivative liabilities	(6,487)	(532)	6,702	(317)	(207)	(524)
Total mark-to-market derivative net assets (liabilities)	$ 326	$ (20)	$ 1,406	$ 1,712	$ (207)	$ 1,505

(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 September 30, 2015, no unrealized balance remains in accumulated OCI to be reclassified by Generation.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — (Continued)
(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 and nine months ended September 30, 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 hedged transactions, result in the ultimate recognition of net revenues or expenses at the contractual price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2015	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at June 30, 2015		$ (21)	$ (19)
Effective portion of changes in fair value		(7)	(8)
Reclassifications from accumulated OCI to net income	Interest Expense	3	3
Accumulated OCI derivative gain at September 30, 2015		$ (25)	$ (24)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Nine Months Ended September 30, 2015	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2014		$ (18)	$ (28)
Effective portion of changes in fair value		(13)	(18)
Reclassifications from accumulated OCI to net income	Other, net	—	16[a]
Reclassifications from accumulated OCI to net income	Interest Expense	8	8
Reclassifications from accumulated OCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative gain at September 30, 2015		$ (25)	$ (24)

(a) Amount is net of related income tax expense of $10 million for the nine months ended September 30, 2015.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Three Months Ended September 30, 2014	Income Statement Location	Total Cash Flow Hedges	Total Cash Flow Hedges
Accumulated OCI derivative gain at June 30, 2014		$ 45[a]	$ 47
Effective portion of changes in fair value		—	(3)
Reclassifications from accumulated OCI to net income	Operating Revenues	(16)[b]	(16)
Accumulated OCI derivative gain at September 30, 2014		$ 29[a]	$ 28

(a) Excludes $13 million of losses, net of taxes, related to interest rate swaps and treasury rate locks as of September 30, 2014 and June 30, 2014.

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

(b) Amount is net of related income tax expense of $12 million for the three months ended September 30, 2014.

Nine Months Ended September 30, 2014	Income Statement Location	Total Cash Flow Hedge OCI Activity, Net of Income Tax — Generation Total Cash Flow Hedges	Exelon Total Cash Flow Hedges
Accumulated OCI derivative gain at December 31, 2013		$ 116[a]	$ 120
Effective portion of changes in fair value		(9)	(14)
Reclassifications from accumulated OCI to net income	Operating Revenues	(78)[b]	(78)
Accumulated OCI derivative gain at September 30, 2014		$ 29[a]	$ 28

(a) Excludes $13 million of losses and $5 million of losses, net of taxes, related to interest rate swaps and treasury locks as of September 30, 2014 and December 31, 2013, respectively.
(b) Amount is net of related income tax expense of $52 million for the nine months ended September 30, 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 nine months ended September 30, 2015. There were no gains recognized for the three months ended September 30, 2015. For the three and nine months ended September 30, 2014, Exelon and Generation recognized a $28 million and $130 million pre-tax gain, respectively. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods relating to energy-related hedges positions as all 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. 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 and nine months ended September 30, 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.

Three Months Ended September 30, 2015	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 136	$ (178)	$ —	$(42)	$ —	$ (42)
Reclassification to realized at settlement of commodity positions	(143)	46	—	(97)	—	(97)

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

Three Months Ended September 30, 2015	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	HoldCo Interest Expense	Exelon Total
Net commodity mark-to-market gains (losses)	(7)	(132)	—	(139)	—	(139)
Change in fair value of treasury positions	2	—	—	2	—	2
Reclassification to realized at settlement of treasury positions	(2)	—	—	(2)	—	(2)
Net treasury mark-to-market gains (losses)	—	—	—	—	—	—
Net mark-to-market gains (losses)	$ (7)	$ (132)	$ —	$(139)	$ —	$(139)

Nine Months Ended September 30, 2015	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 513	$ (163)	$ —	$ 350	$ —	$ 350
Reclassification to realized at settlement of commodity positions	(347)	249	—	(98)	—	(98)
Net commodity mark-to-market gains (losses)	166	86	—	252	—	252
Change in fair value of treasury positions	12	—	—	12	36	48
Reclassification to realized at settlement of treasury positions	(6)	—	—	(6)	64	58
Net treasury mark-to-market gains (losses)	6	—	—	6	100	106
Net mark-to-market gains (losses)	$ 172	$ 86	$ —	$ 258	$ 100	$ 358

Three Months Ended September 30, 2014	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ 181	$ 19	$ —	$ 200	$ —	$ 200
Reclassification to realized at settlement of commodity positions	86	(23)	—	63	—	63
Net commodity mark-to-market gains (losses)	267	(4)	—	263	—	263
Change in fair value of treasury positions	5	—	(3)	2	(8)	(6)
Reclassification to realized at settlement of treasury positions	(1)	—	—	(1)	—	(1)
Net treasury mark-to-market gains (losses)	4	—	(3)	1	(8)	(7)
Net mark-to-market gains (losses)	$ 271	$ (4)	$ (3)	$ 264	$ (8)	$ 256

Nine Months Ended September 30, 2014	Generation Operating Revenues	Generation Purchased Power and Fuel	Generation Interest Expense	Generation Total	HoldCo Interest Expense	Exelon Total
Change in fair value of commodity positions	$ (795)	$ 302	$ —	$(493)	$ —	$(493)
Reclassification to realized at settlement of commodity positions	224	(207)	—	17	—	$ 17

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

Nine Months Ended September 30, 2014	Operating Revenues	Purchased Power and Fuel	Interest Expense	Total	Interest Expense	Total
Net commodity mark-to-market gains (losses)	(571)	95	—	(476)	—	(476)
Change in fair value of treasury positions	1	—	(5)	(4)	(8)	(12)
Reclassification to realized at settlement of treasury positions	(2)	—	—	(2)	—	(2)
Net treasury mark-to-market gains (losses)	(1)	—	(5)	(6)	(8)	(14)
Net mark-to-market gains (losses)	$ (572)	$ 95	$ (5)	$(482)	$ (8)	$(490)

Proprietary Trading Activities (Exelon and Generation). For the three and nine months ended September 30, 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 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 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 September 30,		Nine Months Ended September 30,	
		2015	2014	2015	2014
Change in fair value of commodity positions	Operating Revenues	$ (4)	$ (2)	$ 5	$ (2)
Reclassification to realized at settlement of commodity positions	Operating Revenues	(2)	(10)	(8)	(17)
Net commodity mark-to-market gains (losses)	Operating Revenues	(6)	(12)	(3)	(19)
Change in fair value of treasury positions	Operating Revenues	3	1	7	—
Reclassification to realized at settlement of treasury positions	Operating Revenues	(3)	—	(9)	1
Net treasury mark-to-market gains (losses)	Operating Revenues	—	1	(2)	1
Total Net mark-to-market gains (losses)	Operating Revenues	$ (6)	$ (11)	$ (5)	$ (18)

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.

(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 September 30, 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 $24 million, $33 million and $27 million, as of September 30, 2015, respectively.

Rating as of September 30, 2015	Total Exposure Before Credit Collateral	Credit Collateral[a]	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,463	$ 18	$ 1,445	1	$ 444
Non-investment grade	55	15	40	—	—
No external ratings					
Internally rated — investment grade	535	—	535	—	—
Internally rated — non-investment grade	53	5	48	—	—
Total	$ 2,106	$ 38	$ 2,068	1	$ 444

Net Credit Exposure by Type of Counterparty	As of September 30, 2015
Financial institutions	$ 260
Investor-owned utilities, marketers, power producers	867
Energy cooperatives and municipalities	908
Other	33
Total	$ 2,068

(a) As of September 30, 2015, credit collateral held from counterparties where Generation had credit exposure included $13 million of cash and $25 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 September 30, 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.

PECO's supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier's performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's lowest credit rating from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. The unsecured credit used by the suppliers represents PECO's net credit exposure. As of September 30, 2015, PECO had no net credit exposure to suppliers.

PECO is permitted to recover its costs of procuring electric supply through its PAPUC-approved DSP Program. PECO's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates. See Note 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 September 30, 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 September 30, 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 September 30, 2015, BGE had credit exposure of less than $1 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.

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

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

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

Credit-Risk Related Contingent Feature	September 30, 2015	December 31, 2014
Gross Fair Value of Derivative Contracts Containing this Feature[(a)]	$ (1,533)	$ (1,433)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[(b)]	1,302	1,140
Net Fair Value of Derivative Contracts Containing This Feature[(c)]	$ (231)	$ (293)

(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 $1,065 million and letters of credit posted of $474 million and cash collateral held of $21 million and letters of credit held of $40 million as of September 30, 2015 for external counterparties. 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 external counterparties. 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 $2.1 billion and $2.4 billion as of September 30, 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 September 30, 2015, Generation and Exelon's swaps were in an asset position with a fair value of $3 million and $40 million, respectively.

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 September 30, 2015, ComEd held no 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 September 30, 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 September 30, 2015, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of September 30, 2015, PECO could have been required to post approximately $18 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 September 30, 2015, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of September 30, 2015, BGE could have been required to post approximately $28 million of collateral to its counterparties.

11. 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.

The Registrants had the following amounts of commercial paper borrowings outstanding as of September 30, 2015 and December 31, 2014:

Commercial Paper Borrowings	September 30, 2015	December 31, 2014
Exelon Corporate	$ —	$ —
Generation	—	—
ComEd	604	304
PECO	—	—
BGE	50	120

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at September 30, 2015 for short-term financial needs, as follows:

Type of Credit Facility	Amount[(a)] (In billions)	Expiration Dates	Capacity Type
Exelon Corporate			
Syndicated Revolver[(b)]	$ 0.5	May 2019	Letters of credit and cash
Generation			
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 March 2016	Letters of credit and cash
Bilateral	0.1	January 2017	Letters of credit
Bilateral	0.1	October 2015	Letters of credit and cash
ComEd			
Syndicated Revolver	1.0	March 2019	Letters of credit and cash
PECO			
Syndicated Revolver[(b)]	0.6	May 2019	Letters of credit and cash
BGE			
Syndicated Revolver[(b)]	0.6	May 2019	Letters of credit and cash
Total	$ 8.5		

(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 expired on October 16, 2015 and were renewed at the same amount through October 14, 2016. These facilities are solely utilized to issue letters of credit. As of September 30, 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.

(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.

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

As of September 30, 2015, there were no borrowings under the Registrants' credit facilities.

On October 23, 2015, a $100 million bilateral CENG credit facility was amended and extended for an additional two years. This facility has been utilized by CENG to fund working capital and capital projects. This facility does not back Generation's commercial paper program.

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 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.

Long-Term Debt

Issuance of Long-Term Debt

During the nine months ended September 30, 2015, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon Corporate	Senior Unsecured Notes(a)	1.55%	June 9, 2017	$ 550	Finance a portion of the pending acquisition of PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes(a)	2.85%	June 15, 2020	$ 900	Finance a portion of the pending acquisition of PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes (a)	3.95%	June 15, 2025	$ 1,250	Finance a portion of the pending acquisition of PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes (a)	4.95%	June 15, 2035	$ 500	Finance a portion of the pending acquisition of PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Senior Unsecured Notes (a)	5.10%	June 15, 2045	$ 1,000	Finance a portion of the pending acquisition of PHI and related costs and expenses, and for general corporate purposes
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 111	Procurement of software licenses
Generation	Senior Unsecured Notes (b)	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	2.29 - 2.96%	January 5, 2037	$ 39	Antelope Valley solar development

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

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Generation	Energy Efficiency Project Financing	3.71%	October 1, 2035	$ 42	Funding to install energy conservation measures in Coleman, Florida
Generation	Energy Efficiency Project Financing	3.55%	November 15, 2016	$ 19	Funding to install energy conservation measures in Frederick, Maryland
Generation	Tax Exempt Pollution Control Revenue Bonds (c)	2.50 - 2.70%	2019 - 2020	$ 435	General corporate purposes
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 74	Albany Green Energy biomass generation development
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 PHI acquisition financing, Exelon terminated its interest rate swaps that had been designated as cash flow hedges. See Note 10 — Derivative Financial Instruments for further information.
(b) 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 10 — Derivative Financial Instruments for further information on the swap termination.
(c) The Tax Exempt Pollution Control Revenue Bonds have a mandatory put date that ranges from March 1, 2019—September 1, 2020.

On October 5, 2015, PECO issued $350 million aggregate principal amount of its First and Refunding Mortgage Bonds, 3.15% Series, maturing on October 15, 2025. The proceeds will be used for general corporate purposes.

Merger Financing

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. In June 2015, the remaining $3.2 billion bridge credit facility was terminated as a result of Exelon's issuance of $4.2 billion of long-term debt to fund a portion of the purchase price and related costs and expenses of the merger between Exelon and PHI and for general corporate purposes.

In connection with the $4.2 billion issuance of Senior Unsecured Notes in 2015, the tranches due in 2025, 2035 and 2045 must be redeemed at the principal amount plus a 1% premium of principal upon the earlier of (1) December 31, 2015, if the PHI acquisition is not consummated on or prior to such date, or (2) the date on which the Merger Agreement relating to the PHI acquisition is terminated. Exelon also has the option to redeem those notes earlier at a 1% premium of principal, if Exelon determines that the merger will not be completed before December 31, 2015.

On October 29, 2015, Exelon commenced a private exchange offer (Exchange Offer) to certain eligible holders whereby, for those that take part, the outstanding notes in the 2025, 2035 and 2045 tranches will be exchanged for new notes. The new notes will have substantially the same terms as the outstanding notes, except the outside date with regard to the special redemption provisions is June 30, 2016, rather than December 31, 2015, and under certain circumstances, can be further extended to August 31, 2016. The Exchange Offer's early participation period terminates on November 13, 2015 and its expiration date is November 30, 2015, unless extended. Following the completion of the Exchange Offer, any remaining notes not exchanged are expected to be redeemed pursuant to the terms of such remaining notes. Upon redemption, Exelon will accelerate amortization of previously capitalized debt issuance costs on such notes. As of September 30, 2015, the total unamortized debt issuance costs for the 2025, 2035 and 2045 notes is $22 million.

Albany Green Energy Project Financing (AGE)

Generation owns 90% of Albany Green Energy, LLC (AGE), which is a consolidated variable interest entity (see Note 3—Variable Interest Entities for additional information). In the second quarter of 2015, AGE closed the construction financing and executed an Engineering, Procurement and Construction (EPC) contract to construct a biomass-fueled, combined heat and power facility in Albany, GA. The financing will accumulate and accrue interest throughout construction and is due upon substantial completion of the facility, but no later than November 17, 2017.

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

During the nine months ended September 30, 2014, the following long-term debt was issued:

Company	Type	Interest Rate	Maturity	Amount	Use of Proceeds
Exelon	Junior Subordinated Notes	2.50%	June 1, 2024	$ 1,150	Finance a portion of the acquisition of PHI and for general corporate purposes
Generation	Nuclear Fuel Purchase Contract	3.25 - 3.35%	June 30, 2018	$ 70	Procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 300	General corporate purposes
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 18, 2021	$ 675	General corporate purposes
Generation	Energy Efficiency Project Financing	4.12%	December 31, 2015	$ 12	Funding to install energy conservation measures in Washington, DC
Generation	AVSR DOE Nonrecourse Debt	3.06 - 3.14%	January 5, 2037	$ 125	Antelope Valley solar development
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
PECO	First and Refunding Mortgage Bonds	4.15%	October 1, 2044	$ 300	Refinance existing mortgage bonds and general corporate purposes

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

Retirement and Redemptions of Current and Long-Term Debt

During the nine months ended September 30, 2015, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Exelon Corporate(a)	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Exelon Corporate	Senior Notes	4.90%	June 15, 2015	$ 800
Exelon Corporate	Long Term Software License Agreement	3.95%	May 1, 2024	$ 1
Generation(a)	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Generation	CEU Upstream Nonrecourse Debt	LIBOR + 2.25%	January 14, 2019	$ 9
Generation	AVSR DOE Nonrecourse Debt	2.29%-3.56%	January 5, 2037	$ 12
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 3
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 8, 2021	$ 5
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 14
Generation	Constellation Solar Horizons Nonrecourse Debt	2.56%	September 7, 2030	$ 1
Generation	Sacramento PV Energy Nonrecourse Debt	2.58%	December 31, 2030	$ 1
ComEd	FMB Series 101	4.70%	April 15, 2015	$ 260
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 37

(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 October 5, 2015, Generation paid down $10 million of principal of its 2.29-3.56% AVSR DOE Nonrecourse debt.

On October 15, 2015, Generation paid down $10 million of principal of its LIBOR + 4.25% ExGen Renewables I Nonrecourse debt.

During the nine months ended September 30, 2014, the following long-term debt was retired and/or redeemed:

Company	Type	Interest Rate	Maturity	Amount
Generation	Senior Unsecured Notes	5.35%	January 15, 2014	$ 500
Generation	Pollution Control Notes	4.10%	July 1, 2014	$ 20
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 20
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	ExGen Renewables I Nonrecourse Debt	3mL + 4.25%	February 6, 2021	$ 3
Generation	AVSR DOE Nonrecourse Debt	2.33% - 3.55%	January 5, 2037	$ 4
Generation	Clean Horizons Solar Nonrecourse Debt	2.56%	September 7, 2030	$ 1
Generation	Sacramento Solar Nonrecourse Debt	2.56%	December 31, 2030	$ 1
Generation	Energy Efficiency Project Financing	4.40%	August 31, 2014	$ 9
ComEd	Mortgage Bonds Series 110	1.63%	January 15, 2014	$ 600
ComEd	Pollution Control Series 1994C	5.85%	January 15, 2014	$ 17
BGE	Rate Stabilization Bonds	5.72%	April 1, 2016	$ 35

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

Junior Subordinated Notes

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 and related costs and expenses for 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.

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 ("Contract Payment Obligation") 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. During 2015, contract payments of $33 million related to the Contract Payment Obligation were included within Retirements of long-term debt in Exelon's Consolidated Statements of Cash Flows. During 2014, the Contract Payment Obligation was 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 and Note 23 — Supplemental Financial Information of the Exelon 2014 Form 10-K.

12. 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:

For the Three Months Ended September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
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	2.7	2.1	5.0	1.2	5.3
Qualified nuclear decommissioning trust fund income	(5.4)	(12.5)	—	—	—
Domestic production activities deduction	(4.9)	(11.6)	—	—	—
Health care reform legislation	—	—	—	—	0.2
Amortization of investment tax credit, net deferred taxes	(2.3)	(5.2)	(0.3)	(0.1)	(0.2)
Plant basis differences	(1.4)	—	(0.1)	(7.0)	(0.6)
Production tax credits and other credits	(3.8)	(9.0)	—	—	—
Noncontrolling interest	1.7	3.9	—	—	—
Statute of limitations expiration	(6.4)	(15.2)	—	—	—
Other	1.2	0.4	0.3	—	(0.4)
Effective income tax rate	16.4%	(12.1)%	39.9%	29.1%	39.3%

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

For the Nine Months Ended September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
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	3.1	2.8	5.2	1.2	5.3
Qualified nuclear decommissioning trust fund income	(0.9)	(1.6)	—	—	—
Domestic production activities deduction	(2.8)	(4.9)	—	—	—
Health care reform legislation	—	—	—	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.2)	(1.9)	(0.3)	(0.1)	(0.1)
Plant basis differences	(1.2)	—	(0.1)	(7.3)	(0.4)
Production tax credits and other credits	(2.2)	(3.8)	—	—	—
Noncontrolling interest	—	0.1	—	—	—
Statute of limitations expiration	(1.6)	(2.9)	—	—	—
Other	0.9	0.6	0.2	0.2	(0.1)
Effective income tax rate	29.1%	23.4%	40.0%	29.0%	39.9%

For the Three Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
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	3.4	3.7	5.0	0.1	4.6
Qualified nuclear decommissioning trust fund income	(0.3)	(0.4)	—	—	—
Domestic production activities deduction	(2.4)	(3.2)	—	—	—
Health care reform legislation	—	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.0)	(1.2)	(0.3)	(0.1)	(0.3)
Plant basis differences	(0.8)	—	—	(11.3)	0.5
Production tax credits and other credits	(1.9)	(2.4)	—	—	—
Noncontrolling interest	(1.2)	(1.6)	—	—	—
Statute of limitations expiration	(3.8)	(5.0)	—	—	—
Other	1.2	0.6	0.1	(0.1)	(1.2)
Effective income tax rate	28.2%	25.5%	40.0%	23.6%	38.8%

For the Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
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	2.0	1.2	5.0	0.3	4.9
Qualified nuclear decommissioning trust fund income	2.0	3.6	—	—	—
Domestic production activities deduction	(2.7)	(4.8)	—	—	—
Health care reform legislation	0.1	—	0.2	—	0.2
Amortization of investment tax credit, net deferred taxes	(1.1)	(1.7)	(0.3)	(0.1)	(0.3)
Plant basis differences	(1.6)	—	(0.3)	(11.0)	0.5
Production tax credits and other credits	(2.1)	(3.7)	—	—	—
Noncontrolling interest	(1.4)	(2.6)	—	—	—
Statute of limitations expiration	(2.5)	(4.4)	—	—	—
Other	(0.5)	(0.7)	0.1	0.1	(0.5)
Effective income tax rate	27.2%	21.9%	39.7%	24.3%	39.8%

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $1,204 million, $660 million, $144 million, $0 million, and $120 million, of unrecognized tax benefits as of September 30, 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 September 30, 2015 reflect a decrease at Exelon, Generation, and PECO primarily attributable to the disallowed AmerGen claims discussed below and the resolution of state income tax positions at Generation. The unrecognized tax benefits as of September 30, 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

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, reduced Generation and PECO's unrecognized tax benefits by $661 million and $43 million, respectively, in the first quarter of 2015. This change in unrecognized tax benefits had no impact on Exelon, Generation, or PECO'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

Like-Kind Exchange

As of September 30, 2015, Exelon and ComEd have approximately $394 million and $144 million of unrecognized tax benefits that could significantly decrease within the 12 months after the reporting date as a result of a decision in the like-kind exchange litigation described below. Exelon and ComEd have unrecognized tax benefits that, if recognized, would decrease Exelon's effective tax rate by $71 million and increase ComEd's effective tax rate by $11 million.

Settlement of Income Tax Audits

As of September 30, 2015, Exelon, Generation, and BGE have approximately $261 million, $141 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 $141 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 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 took place in August of 2015. Exelon was not required to remit any part of the asserted tax or penalty in order to litigate the issue. While the Tax Court could reach its decision as early as 2016, the litigation could take three to five years if appeals are necessary. Decisions in the Tax Court are not controlled by the Federal Circuit’s decision in Consolidated Edison.

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

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. In connection with the termination, Exelon will deposit $260 million with the IRS for its 2014 tax year, including $135 million by ComEd representing the remaining gain deferred pursuant to the like-kind exchange transaction. The deposit can be redesignated to any tax year, if necessary, and may be used to satisfy any amounts owed as a result of the litigation.

In the event of a fully successful IRS challenge to Exelon's like-kind exchange position, the potential tax and after-tax interest, net of the deposit discussed above and exclusive of penalties, that could become currently payable as of September 30, 2015 may be as much as $560 million, of which approximately $165 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. Interest will continue to accrue until such time as payment is made. An appeal of an adverse decision in the Tax Court would necessitate either the posting of a bond or the payment of the tax and interest for the tax years before the court. A final appellate decision could take several years.

13. 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 September 30, 2015:

Nuclear decommissioning ARO at December 31, 2014[(a)]	$6,961
Net increase due to changes in, and timing of, estimated future cash flows	831
Accretion expense	283
Costs incurred to decommission retired plants	(2)
Nuclear decommissioning ARO at September 30, 2015[(a)]	$8,073

(a) Includes $7 million and $8 million as the current portion of the ARO at September 30, 2015 and December 31, 2014 respectively, which is included in Other current liabilities on Exelon's and Generation's Consolidated Balance Sheets.

During the nine months ended September 30, 2015, Generation's total nuclear ARO increased by approximately $1.1 billion, reflecting impacts of ARO updates completed during the first and third quarters of 2015 to reflect changes in amounts and timing of estimated decommissioning cash flows and impacts of year-to-date accretion of the ARO liability due to the passage of time.

In the first quarter of 2015, the ARO liability was increased by $55 million to reflect a purchase accounting adjustment to the fair value of the CENG ARO liability as of April 1, 2014, the date of the consolidation of CENG. See Note 6 — Investment in Constellation Energy Nuclear Group, LLC for additional information. The third quarter 2015 annual update further increased the ARO liability by a net $775 million, which was primarily driven by an increase of approximately $550 million for costs expected to be incurred for required site security during the decommissioning periods in which SNF remains onsite and until major reactor components and buildings have been dismantled and removed. This projected increase is based on emerging industry experience at nuclear sites in the planning or early stage of decommissioning indicating greater than originally expected numbers of security personnel required to be on site during these decommissioning periods. Generation will continue to monitor emerging security cost trends, including potential strategies to limit such costs by, for example, optimizing the transfer of SNF when DOE starts taking possession of SNF or increasing the use of dry SNF storage, and will adjust the ARO liability accordingly. The third quarter 2015 adjustment to the ARO includes an increase of $285 million for the impacts of a change implemented in the 2015 annual assessment of Generation's SNF storage and disposal cost estimation methodology to better align the projected timing of SNF transfers to the DOE with assumed plant shutdown dates. The third quarter 2015 net increase to the ARO further reflects higher assumed probabilities of early retirements of certain economically challenged nuclear plants (See Note 8 — Implications of Potential Early Plant Retirements for additional information) and net increases in the estimated costs for Peach Bottom and Salem nuclear units pursuant to updated decommissioning cost studies received during 2015; partially offset by reductions in estimated cost escalation rates, primarily for labor and energy costs.

The financial statement impact related to the increase in the ARO due to the changes in, and timing of, estimated cash flows primarily resulted in a corresponding increase in Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. Approximately $8 million of the third quarter adjustment resulted in a credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

During the nine months ended September 30, 2014, Generation's ARO increased by approximately $1.8 billion. The increase is largely driven by the recording of an ARO on Exelon's and Generation's Consolidated Balance Sheets at fair value, including subsequent purchase accounting adjustments, upon consolidation of CENG during the second quarter (see Note 6 — Investment in Constellation Energy Nuclear Group, LLC). The change in the ARO was also driven by an increase in the estimated costs to decommission the Byron and Braidwood nuclear units pursuant to updated decommissioning costs studies received during the third quarter 2014 as part of the annual assessment. These increases in the ARO were partially offset by decreases in the ARO due to reductions in estimated escalation rates, primarily for labor and energy costs. The increase in the ARO due to the changes in, and timing of, estimated cash flows primarily resulted in a corresponding increase in Property, plant and equipment on Exelon's and Generation's Consolidated Balance Sheets. Approximately $16 million of the change in the ARO resulted in a credit to income, which is included in Operating and maintenance expense within Exelon's and Generation's Consolidated Statements of Operations and Comprehensive Income.

Nuclear Decommissioning Trust Fund Investments

At September 30, 2015 and December 31, 2014, Exelon and Generation had NDT fund investments totaling $10,103 million and $10,537 million, respectively.

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

The following table provides unrealized gains (losses) on NDT funds for the three and nine months ended September 30, 2015 and 2014:

	Exelon and Generation			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net unrealized gains (losses) on decommissioning trust funds — Regulatory Agreement Units[a]	$ (301)	$ (107)	$ (385)	$ 126
Net unrealized gains (losses) on decommissioning trust funds — Non-Regulatory Agreement Units[b][c]	(218)	(41)	(274)	100

(a) Net unrealized gains (losses) related to Generation's NDT funds associated with Regulatory Agreement Units are included in Regulatory liabilities on Exelon's Consolidated Balance Sheets and Noncurrent payables to affiliates on Generation's Consolidated Balance Sheets.
(b) Excludes $7 million of net unrealized gains related to the Zion Station pledged assets for the three months ended September 30, 2014 and $9 million and $27 million of net unrealized gains related to the Zion Station pledged assets for the nine months ended September 30, 2015 and 2014, respectively. 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 (losses) 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 completing certain decommissioning activities at 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, are 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 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 $82 million, which is included within the nuclear decommissioning ARO at September 30, 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 September 30, 2015 and December 31, 2014:

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

	Exelon and Generation	
	September 30, 2015	December 31, 2014
Carrying value of Zion Station pledged assets	$ 237	$ 319
Payable to Zion Solutions[(a)]	217	292
Current portion of payable to Zion Solutions[(b)]	118	137
Cumulative withdrawals by Zion Solutions to pay decommissioning and other costs[(c)]	757	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.
(c) Includes project expenses to decommission Zion Station and estimated tax payments on Zion Station NDT Fund earnings.

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. The increased security costs discussed above will be taken into consideration, as appropriate and in accordance with the regulatory requirements, in Generation's future decommissioning funding status reports submitted to the NRC. Generation does not expect the increased costs to change Generation's NRC minimum funding assurance status.

14. 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.

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

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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 $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 tables present the components of Exelon's net periodic benefit costs, prior to any capitalization, for the three and nine months ended September 30, 2015 and 2014.

	Pension Benefits Three Months Ended September 30,		Other Postretirement Benefits Three Months Ended September 30,	
	2015[a]	2014[a]	2015[a]	2014[a]
Service cost	$ 82	$ 74	$ 30	$ 27
Interest cost	178	189	42	42
Expected return on assets	(257)	(251)	(38)	(39)
Amortization of:				
Prior service cost (benefit)	3	3	(43)	(44)
Actuarial loss	142	106	20	15
Net periodic benefit cost	$ 148	$ 121	$ 11	$ 1

	Pension Benefits Nine Months Ended September 30,		Other Postretirement Benefits Nine Months Ended September 30,	
	2015[b]	2014[b]	2015[b]	2014[b]
Service cost	$ 245	$ 218	$ 89	$ 90
Interest cost	533	561	125	144
Expected return on assets	(770)	(743)	(113)	(115)
Amortization of:				
Prior service cost (benefit)	10	10	(130)	(79)
Actuarial loss	427	316	60	35
Net periodic benefit cost	$ 445	$ 362	$ 31	$ 75

(a) For the three months ended September 30, 2015, the cost for pension benefits and other postretirement benefits related to CENG were $2 million and $3 million, respectively. For the three months ended September 30, 2014, the cost for pension benefits and other postretirement benefits related to CENG were $2 million and $3 million, respectively. CENG amounts are included in the tables above.

(b) For the nine months ended September 30, 2015, the cost for pension benefits and other postretirement benefits related to CENG were $8 million and $8 million, respectively. For the period of April 1, 2014 to September 30, 2014, the cost for pension benefits and other postretirement benefits related to CENG were $5 million and $6 million, respectively. CENG amounts are included in the tables above.

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

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 and nine months ended September 30, 2015 and 2014.

Pension and Other Postretirement Benefit Costs	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Generation[(a)]	$ 67	$ 54	$ 200	$ 193
ComEd	52	33	155	129
PECO	10	7	29	28
BGE	16	17	49	50
BSC[(b)]	14	11	43	37

(a) For the three and nine months ended September 30, 2015, the costs related to CENG were $5 million and $16 million, respectively. For the three months ended September 30, 2014, the costs related to CENG were $5 million. For the period of April 1, 2014 to September 30, 2014, the costs related to CENG were $11 million. CENG amounts are included in the table above.

(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.

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 and nine months ended September 30, 2015 and 2014:

Savings Plan Matching Contributions	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Exelon[(a)]	$ 51	$ 34	$ 111	$ 82
Generation[(a)]	27	17	60	41
ComEd	10	8	23	20
PECO	3	2	7	6
BGE	5	3	10	7
BSC[(b)]	6	4	11	8

(a) Includes $4 million and $8 million, respectively, related to CENG for the three and nine months ended September 30, 2015. Includes $1 million related to CENG for the three months ended September 30, 2014 and for the period from April 1, 2014 to September 30, 2014.

(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.

15. 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.

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

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. These benefits are accrued for when the benefits are considered probable and can be reasonably estimated.

For the three and nine months ended September 30, 2015 and 2014, the Registrants recorded the following severance costs (benefits) associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

	Exelon	Generation	ComEd	PECO	BGE
Three Months Ended					
September 30, 2015	$ (3)	$ (3)	$ —	$ —	$ —
September 30, 2014	(2)	(2)	—	—	—
Nine Months Ended					
September 30, 2015	$ 18	$ 17	$ 1	$ —	$ —
September 30, 2014	4	3	1	—	—

The severance liability balances associated with these ongoing severance benefits as of September 30, 2015 and December 31, 2014 are not material.

16. 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 nine months ended September 30, 2015 and 2014:

Nine Months Ended September 30, 2015	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
Exelon[a]						
Beginning balance	$ (28)	$ 3	$ (2,640)	$ (19)	$ —	$(2,684)
OCI before reclassifications	(18)	—	(29)	(17)	—	(64)
Amounts reclassified from AOCI[b]	22	—	130	—	—	152
Net current-period OCI	4	—	101	(17)	—	88
Ending balance	$ (24)	$ 3	$ (2,539)	$ (36)	$ —	$(2,596)
Generation[a]						
Beginning balance	$ (18)	$ 1	$ —	$ (19)	$ —	$ (36)
OCI before reclassifications	(13)	—	—	(17)	—	(30)
Amounts reclassified from AOCI[b]	6	—	—	—	—	6
Net current-period OCI	(7)	—	—	(17)	—	(24)
Ending balance	$ (25)	$ 1	$ —	$ (36)	$ —	$ (60)

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

Nine Months Ended September 30, 2015	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
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
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.

Nine Months Ended September 30, 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
Exelon[a]						
Beginning balance	$ 120	$ 2	$ (2,260)	$ (10)	$ 108	$(2,040)
OCI before reclassifications	(14)	(2)	240	(6)	11	229
Amounts reclassified from AOCI[b]	(78)	—	91	—	(119)	(106)
Net current-period OCI	(92)	(2)	331	(6)	(108)	123
Ending balance	$ 28	$ —	$ (1,929)	$ (16)	$ —	$(1,917)
Generation[a]						
Beginning balance	$ 114	$ 2	$ —	$ (10)	$ 108	$ 214
OCI before reclassifications	(8)	(3)	—	(6)	11	(6)
Amounts reclassified from AOCI[b]	(78)	—	—	—	(119)	(197)
Net current-period OCI	(86)	(3)	—	(6)	(108)	(203)
Ending balance	$ 28	$ (1)	$ —	$ (16)	$ —	$ 11
PECO[a]						
Beginning balance	$ —	$ 1	$ —	$ —	$ —	$ 1
OCI before reclassifications	—	—	—	—	—	—
Amounts reclassified from AOCI[b]	—	—	—	—	—	—
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.

ComEd, PECO, and BGE did not have any reclassifications out of AOCI to Net income during the three and nine months ended September 30, 2015 and 2014. The following tables present amounts reclassified out of AOCI to Net income for Exelon and Generation during the three and nine months ended September 30, 2015 and 2014.

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

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Three Months Ended September 30, 2015

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statements of Operations and Comprehensive Income
Gains (losses) on hedging activity			
Other cash flow hedges	$ (4)	$ (4)	Interest expense
	(4)	(4)	Total before tax
	1	1	Tax benefit
	$ (3)	$ (3)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ 19	$ —	
Actuarial losses [b]	(90)	—	
	(71)	—	Total before tax
	28	—	Tax benefit
	$ (43)	$ —	Net of tax
Total Reclassifications for the period	$ (46)	$ (3)	Net of Tax

Nine Months Ended September 30, 2015

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statements of Operations and Comprehensive Income
Gains (losses) on hedging activity			
Terminated interest rate swaps[c]	$ (26)	$ —	Other, net
Energy related hedges	2	2	Operating revenues
Other cash flow hedges	(11)	(11)	Interest expense
	(35)	(9)	Total before tax
	13	3	Tax benefit
	$ (22)	$ (6)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs [b]	$ 57	$ —	
Actuarial losses [b]	(270)	—	
	(213)	—	Total before tax
	83	—	Tax benefit
	$ (130)	$ —	Net of tax
Total Reclassifications for the period	$ (152)	$ (6)	Net of Tax

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

Three months ended September 30, 2014

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Items reclassified out of AOCI[(a)] Generation	Affected line item in the Statements of Operations and Comprehensive Income
Gains on hedging activity			
Energy related hedges	$ 28	$ 28	Operating revenues
	28	28	Total before tax
	(12)	(12)	Tax (expense)
	$ 16	$ 16	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[(b)]	$ 19	$ —	
Actuarial losses[(b)]	(61)	—	
	(42)	—	Total before tax
	16	—	Tax benefit
	$ (26)	$ —	Net of tax
Equity investments			
Reversal of CENG equity method AOCI	$ 5	$ 5	Gain on consolidation of CENG
	5	5	Total before tax
	(2)	(2)	Tax benefit
	$ 3	$ 3	Net of tax
Total reclassifications for the period	$ (7)	$ 19	Net of Tax

Nine Months Ended September 30, 2014

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Items reclassified out of AOCI[(a)] Generation	Affected line item in the Statements of Operations and Comprehensive Income
Gains on hedging activity			
Energy related hedges	$ 130	$ 130	Operating revenues
	130	130	Total before tax
	(52)	(52)	Tax (expense)
	$ 78	$ 78	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[(b)]	$ 29	$ —	
Actuarial losses[(b)]	(178)	—	
	(149)	—	Total before tax
	58	—	Tax benefit
	$ (91)	$ —	Net of tax

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

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Items reclassified out of AOCI[(a)] Generation	Affected line item in the Statements of Operations and Comprehensive Income
Equity investments			
Sale of equity method investment	$ 5	$ 5	Gain on consolidation of CENG
Reversal of CENG equity method AOCI	193	193	Gain on consolidation of CENG
	198	198	Total before tax
	(79)	(79)	Tax benefit
	$ 119	$ 119	Net of tax
Total reclassifications for the period	$ 106	$ 197	Net of Tax

(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 14 — 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 and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 8	$ 8	$ 22	$ 11
Actuarial loss reclassified to periodic cost	(35)	(24)	(105)	(69)
Pension and non-pension postretirement benefit plans valuation adjustment	—	5	17	(153)
Change in unrealized (gain) loss on cash flow hedges	3	15	(3)	62
Change in unrealized income on equity investments	—	3	—	73
Change in unrealized loss on marketable securities	—	1	—	(1)
Total	$ (24)	$ 8	$ (69)	$ (77)
Generation				
Change in unrealized loss on cash flow hedges	$ 3	$ 13	$ 4	$ 57
Change in unrealized income on equity investments	—	3	—	73
Change in marketable securities	—	1	—	(1)
Total	$ 3	$ 17	$ 4	$ 129

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

17. Common Stock (Exelon)

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 and entered into forward sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreements by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion, which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. Use of net proceeds will be to fund the pending acquisition of PHI and related costs and expenses, and for general corporate purposes.

The forward sale agreements are classified as equity transactions. As a result, no amounts were recorded in the consolidated financial statements until the July 2015 settlement of the forward sale agreements. However, prior to the July 2015 settlement, incremental shares, if any, were included within the calculation of diluted EPS using the treasury stock method. For further information on the transaction, refer to Note 19—Common Stock of the Exelon 2014 Form 10-K.

Concurrent with the June 2014 forward equity transaction, Exelon also issued $1.15 billion of junior subordinated notes in the form of 23 million equity units. See Note 11 — Debt and Credit Agreements for further information on the equity units.

18. 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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income attributable to common shareholders	$ 629	$ 993	$ 1,959	$ 1,604
Average common shares outstanding — basic	913	861	879	860
Potentially dilutive effect of stock options, performance share awards and restricted stock	2	2	4	3
Average common shares outstanding — diluted	915	863	883	863

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 14 million for the three and nine months ended September 30, 2015 and 16 million for the three and nine months ended September 30, 2014. 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 4 million and 2 million for the three and nine months ended September 30, 2015, respectively, and 2 million for the three months ended September 30, 2014 and 1 million for the nine months ended September 30, 2014. 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 and nine months ended September 30, 2015, and approximately 2 million not included for the three months ended September 30, 2014 and 1 million not included for the nine months ended September 30, 2014. Refer to Note 17 — 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 September 30, 2015. In 2008, Exelon management decided to defer indefinitely any share repurchases.

19. 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.

Commitments

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 for office space 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 $575 million to $650 million relating to Exelon and Generation's development or assistance in the development of 275 — 300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. Exelon and Generation have incurred $353 million towards satisfying the commitment for new generation development in the state of Maryland, with approximately 160 MW of the new generation commencing with commercial operations to date. 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 for the nine and three months ended September 30, 2014. 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.

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

Equity Investment Commitments

As part of Generation's investments in technology development, Generation enters into equity purchase agreements that include commitments to invest additional equity through incremental payments 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 September 30, 2015, Generation's estimated commitment relating to its equity purchase agreements, including in-kind services contributions, is anticipated to be as follows:

	Total
2015	$ 38
2016	276
2017	23
2018	7
2019	2
Total	$346

Contingencies

Commercial Commitments

The Registrants' commercial commitments as of September 30, 2015, representing commitments potentially triggered by future events were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)[(a)]	$1,078	$ 1,011	$ 18	$ 22	$ 1
Guarantees	5,823[(b)]	3,159[(c)]	205[(d)]	188[(e)]	263[(f)]
Nuclear insurance premiums[(g)]	3,057	3,057	—	—	—
Total commercial commitments	$9,958	$ 7,227	$ 223	$210	$264

(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 $650 million at September 30, 2015, which represents the total amount Exelon could be required to fund based on September 30, 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 $475 million at September 30, 2015, which represents the total amount Generation could be required to fund based on September 30, 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.

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 September 30, 2015, the current liability limit per incident was $13.4 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 September 30, 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 102 reactors) resulting in an additional $12.9 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 $13.4 billion limit for a single incident.

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 2020.
- 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. For more information, see the discussion of the Riverside site below.

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 —

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

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.

As of September 30, 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:

September 30, 2015	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 376	$ 309
Generation	63	—
ComEd	269	268
PECO	41	39
BGE	3	2

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

The historical nature of the MGP sites and the fact that many of the sites have been buried and built over, impacts the ability to determine a precise estimate of the ultimate costs prior to initial sampling and determination of the exact scope and method of remedial activity. Management determines its best estimate of remediation costs using all available information at the time of each study, including probabilistic and deterministic modeling for ComEd and PECO, and the remediation standards currently required by the applicable state environmental agency. Prior to completion of any significant clean up, each site remediation plan is approved by the appropriate state environmental agency.

During the third quarter of 2015, ComEd and PECO completed an annual study of their future estimated MGP remediation requirements. For ComEd, the results of the study resulted in a $50 million increase to ComEd’s environmental liabilities and related regulatory assets. The increase at ComEd was primarily driven by refined assumptions and scopes based on further experience and analysis, including one site where a new option is being considered for a facility under which contamination exists and certain sites where another PRP leads the remediation efforts and ComEd shares responsibility. For PECO, the results of the study resulted in a $1 million decrease to PECO’s environmental liabilities and related regulatory assets.

The Registrants cannot reasonably estimate whether they will incur other significant liabilities for additional investigation and remediation costs at these or additional sites identified by the Registrants, environmental agencies or others, or whether such costs will be recoverable from third parties, including customers.

Water 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 $12 million at September 30, 2015 and $13 million at December 31, 2014.

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 Generations' share of liability as a result of the rejection of the asbestos cost sharing agreement in the bankruptcy 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 September 30, 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. Since June 2012, the U.S. EPA has requested that the PRPs perform a series of additional analyses and groundwater and soil sampling as part of the supplemental feasibility study, that are now scheduled to be conducted through 2016. 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 2017 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 U.S. EPA is also reviewing a partial excavation remedy; however, until the current sampling is concluded there is no basis to determine the likelihood and estimate of a partial excavation remedy. The current estimated cost of the landfill cover remediation for the site is approximately $60 million, which will be allocated among all PRPs. Recent investigation has identified a number of other parties who may be PRPs and could be liable to contribute to the final remedy. Further investigation is underway. 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 2016 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.

Commencing in February 2012, 36 lawsuits have been filed in the U.S. District Court for the Eastern District of Missouri. Among the defendants were Exelon (subsequently dismissed from the case), 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. 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. The court has dismissed the lawsuits filed by 30 of the plaintiffs. Pre-trial motions and discovery are proceeding in the remaining cases and a proposed pre-trial scheduling order has been filed with the court. At this stage of the litigation, Generation and ComEd cannot estimate a range of loss, if any.

68th Street Dump. In 1999, the U.S. EPA proposed to add the 68th Street Dump in Baltimore, Maryland to the Superfund National Priorities List, and notified BGE and 19 others that they are PRPs at the site. In March 2004, BGE and other PRPs formed the 68th Street Coalition and entered into consent order negotiations with the U.S. EPA to investigate clean-up options for the site under the Superfund Alternative Sites Program. In May 2006, a settlement among the U.S. EPA and 19 of the PRPs, including BGE, with respect to investigation of the site became effective. The settlement requires the PRPs, over the course of several years, to identify contamination at the site and recommend clean-up options. The 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 $9 million, which has been fully reserved as of September 30, 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 PRP's signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP's to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for 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.

Riverside. In 2013, the Maryland Department of the Environment (MDE), at the request of U.S. EPA, conducted a site inspection and limited environmental sampling of certain portions of the 170 acre Riverside property owned by BGE. The site consists of several different parcels with different current and historical uses.

The sampling included soil and groundwater samples for a number of potential environmental contaminants. The sampling confirmed the existence of contaminants consistent with the known historical uses of the various portions of the site. In March 2014, the MDE requested that BGE conduct an investigation of three specific areas of the site, and a site-wide investigation of soils, sediment, groundwater, and surface water to complement the MDE sampling. The field investigation was completed in January 2015, and a final report was provided to MDE on June 2, 2015. Upon completion of the investigation the MDE will determine if the site requires further action and/or remediation. Based upon the investigation to date, BGE has established what it believes is an appropriate reserve. As the investigation and potential remediation proceed, it is possible that additional reserves could be established, in amounts that could be material to BGE.

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 September 30, 2015 and December 31, 2014, Generation had reserved approximately $95 million and $100 million, respectively, in total for asbestos-related bodily injury claims. As of September 30, 2015, approximately $20 million of this amount related to 217 open claims presented to Generation, while the remaining $75 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. Since the Pennsylvania Supreme Court’s ruling in November 2013 , Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been reserved against on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On June 27, 2014, the Illinois Court of Appeals ruled that the Illinois Worker’s Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker’s Compensation claim. This decision is now on appeal to the Illinois Supreme Court. If confirmed on appeal, former employees could file suit against Exelon, Generation, and ComEd, similar to the way former employees are filing suit against Exelon in Pennsylvania. Currently, Exelon, Generation, and ComEd 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 September 30, 2015.

There is a reasonable possibility that Exelon may have additional exposure to estimated future asbestos-related bodily injury claims in excess of the amount accrued and the increases could have a material adverse effect on Exelon's, Generation's, PECO's and ComEd'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 468 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.

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.

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 September 30, 2015. On September 11, 2015, the court granted final approval of the settlement. ComEd deposited funds for the settlement directly into an escrow account in September 2015, with payments to the class expected to commence in the fourth quarter 2015.

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.

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

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

20. 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 and nine months ended September 30, 2015 and 2014:

Three Months Ended September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 39	$ 39	$ —	$ —	$ —
Non-regulatory agreement units	18	18	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(301)	(301)	—	—	—
Non-regulatory agreement units	(218)	(218)	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	207	207	—	—	—
Total decommissioning-related activities	(255)	(255)	—	—	—
Investment income (expense)	4	1	—	(1)	1[c]
Long-term lease income	4	—	—	—	—
AFUDC — Equity	6	—	1	1	4
Other	(3)	(3)	3	1	(1)
Other, net	$(244)	$ (257)	$ 4	$ 1	$ 4

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

Nine Months Ended September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[(a)]					
Regulatory agreement units	$ 203	$ 203	$ —	$ —	$ —
Non-regulatory agreement units	122	122	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(385)	(385)	—	—	—
Non-regulatory agreement units	(274)	(274)	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	9	9	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	129	129	—	—	—
Total decommissioning-related activities	(196)	(196)	—	—	—
Investment income (expense)	6	1	—	(1)	3[(c)]
Long-term lease income	12	—	—	—	—
Interest income related to uncertain income tax positions	—	1	—	—	—
AFUDC — Equity	16	—	2	4	10
Terminated interest rate swaps[(d)]	(26)	—	—	—	—
Other	9	1	12	—	—
Other, net	$(179)	$ (193)	$ 14	$ 3	$ 13

Three Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[(a)]					
Regulatory agreement units	$ 55	$ 55	$ —	$ —	$ —
Non-regulatory agreement units	39	39	—	—	—
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(107)	(107)	—	—	—
Non-regulatory agreement units	(41)	(41)	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	7	7	—	—	—
Regulatory offset to decommissioning trust fund-related activities[(b)]	29	29	—	—	—
Total decommissioning-related activities	(18)	(18)	—	—	—
Investment income (expense)	—	—	—	—	1[(c)]
Long-term lease income	4	—	—	—	—
Interest income related to uncertain income tax positions	25	27			
AFUDC — Equity	5	—	—	2	3
Other	—	(5)	4	—	—
Other, net	$ 16	$ 4	$ 4	$ 2	$ 4

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

Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 167	$ 167	$ —	$ —	$ —
Non-regulatory agreement units	102	102	—	—	—
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	126	126	—	—	—
Non-regulatory agreement units	100	100	—	—	—
Net unrealized gains on pledged assets					
Zion Station decommissioning	27	27	—	—	—
Regulatory offset to decommissioning trust fund-related activities[b]	(270)	(270)	—	—	—
Total decommissioning-related activities	252	252	—	—	—
Investment income (expense)	1	1	—	(1)	5[c]
Long-term lease income	20	—	—	—	—
Interest income related to uncertain income tax positions	41	53	—	—	—
AFUDC — Equity	17	—	3	5	9
Other	15	—	11	1	—
Other, net	$ 346	$ 306	$ 14	$ 5	$ 14

(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 nine months ended September 30, 2015 and 2014:

Nine Months Ended September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,648	$ 739	$ 471	$179	$216
Regulatory assets	131	—	57	19	55
Amortization of intangible assets, net	39	35	—	—	—
Amortization of energy contract assets and liabilities[a]	(20)	(19)	—	—	—
Nuclear fuel[b]	841	841	—	—	—
ARO accretion[c]	291	291	—	—	—
Total depreciation, amortization, accretion and depletion	$2,930	$ 1,887	$ 528	$198	$271

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

Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$1,549	$ 686	$ 438	$169	$215
Regulatory assets	150	—	83	7	60
Amortization of intangible assets, net	33	33	—	—	—
Amortization of energy contract assets and liabilities[a]	83	93	—	—	—
Nuclear fuel[b]	790	790	—	—	—
ARO accretion[c]	251	251	—	—	—
Total depreciation, amortization, accretion and depletion	$2,856	$ 1,853	$ 521	$176	$275

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

Nine Months Ended September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 476	$ 200	$ 155	$ 29	$ 49
Loss from equity method investments	3	4	—	—	—
Provision for uncollectible accounts	114	15	46	37	15
Stock-based compensation costs	102	—	—	—	—
Other decommissioning-related activity[a]	(31)	(31)	—	—	—
Energy-related options[b]	18	18	—	—	—
Amortization of rate stabilization deferral	60	—	—	—	60
Amortization of debt fair value adjustment	(34)	(9)	—	—	—
Discrete impacts of EIMA[c]	101	—	101	—	—
Amortization of debt costs	43	12	3	2	2
Increase in inventory reserve	7	8	—	—	—
Lower of cost or market inventory adjustment	15	15	—	—	—
Other	(18)	(5)	7	1	(15)
Total other non-cash operating activities	$ 856	$ 227	$ 312	$ 69	$ 111
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 47	$ —	$ 27	$ 12	$ 8
Other regulatory assets and liabilities	(12)	—	29	(4)	(106)
Cash deposits[d]	(190)	(190)	—	—	—
Other current assets	(132)	(143)	2	(23)[e]	55
Other noncurrent assets and liabilities	(193)	(92)	(65)	(3)	—
Total changes in other assets and liabilities	$(480)	$ (425)	$ (7)	$ (18)	$ (43)
Non-cash investing and financing activities:					
Change in PPE related to the ARO update	$ 811	$ 811	$ —	$ —	$ —
Change in capital expenditures not paid	59[j]	48[j]	62	(23)	(14)
Non-cash financing of capital projects	52	52	—	—	—
Indemnification of like-kind exchange position[f]	—	—	5	—	—
Long-term software licensing agreement[g]	95	—	—	—	—

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

Nine Months Ended September 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 437	$ 193	$ 129	$ 28	$ 50
Equity method investments	20	20	—	—	—
Provision for uncollectible accounts	96	10	9	39	38
Stock-based compensation costs	111	—	—	—	—
Other decommissioning-related activity[a]	(102)	(102)	—	—	—
Energy-related options[b]	92	92	—	—	—
Amortization of regulatory asset related to debt costs	8	—	—	—	—
Amortization of rate stabilization deferral	50	—	—	—	50
Amortization of debt fair value adjustment	(45)	(17)	—	—	—
Discrete impacts from EIMA[c]	(32)	—	(32)	—	—
Amortization of debt costs	36	9	4	2	2
Merger-related commitments	44	44	—	—	—
Other	(17)	2	6	1	(11)
Total other non-cash operating activities	$ 698	$ 251	$ 116	$ 70	$129
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 53	$ —	$ 63	$ (14)	$ 6
Other regulatory assets and liabilities	(63)	—	(14)	(14)	(89)
Cash deposits[d]	(280)	(280)	—	—	—
Other current assets	(78)	24	(9)	(48)[e]	25
Other noncurrent assets and liabilities	(168)	(111)	22	1	(9)
Total changes in other assets and liabilities	$ (536)	$ (367)	$ 62	$ (75)	$ (67)
Non-cash investing and financing activities:					
Fair value of net assets recorded upon CENG consolidation	$3,400	$ 3,400	$ —	$ —	$ —
Change in PPE related to the ARO update	(91)	(91)			
Change in capital expenditures not paid	(73)[j]	(100)[j]	13	(13)	31
Issuance of equity units[h]	131	—	—	—	—
Uranium procurement[i]	70	70	—	—	—
Indemnification of like-kind exchange position[f]	—	—	4	—	—

(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 made to ISOs/RTOs.
(e) Relates primarily to prepaid utility taxes.
(f) See Note 12 — Income Taxes for discussion of the like-kind exchange tax position.
(g) Relates to a long-term software license agreement entered into on May 31, 2015. Exelon is required to make payments starting August of 2015 through May of 2024. See Note 11 —Debt and Credit Agreements for additional information.
(h) Relates to the present value of the contract payments for the equity units issued by Exelon. See Note 17—Common Stock for additional information.
(i) Relates to the nuclear fuel procurement contracts for the purchase of fixed quantities of uranium, which was delivered to Generation on June 30, 2014 and September 24, 2014. Generation is required to make payments starting June 30, 2016, with the final payment being due no later than June 30, 2018.
(j) Includes $22 million of changes in capital expenditures not paid between December 31, 2014 and September 30, 2015 and $175 million between December 31, 2013 and September 30, 2014 related to Antelope Valley.

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

DOE Smart Grid Investment Grant (Exelon and PECO). For the nine months ended September 30, 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 $5 million related to PECO's DOE SGIG programs. For the nine months ended September 30, 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.

Supplemental Balance Sheet Information

The following tables provide additional information about assets of the Registrants as of September 30, 2015 and December 31, 2014.

September 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$16,185[(a)]	$ 8,659[(a)]	$3,614	$3,058	$2,962
Accounts receivable:					
Allowance for uncollectible accounts	329[(c)]	70	100	98[(c)]	61

December 31, 2014	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$14,742[(b)]	$ 7,612[(b)]	$3,432	$2,917	$2,868
Accounts receivable:					
Allowance for uncollectible accounts	311[(c)]	60	84	100[(c)]	67

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $3,093 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,673 million.
(c) Excludes the non-current allowance for uncollectible accounts related to PECO's installment plan receivables described below of $9 million and $7 million at September 30, 2015 and December 31, 2014, respectively.

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 $15 million as of September 30, 2015 and December 31, 2014 each. 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 September 30, 2015 of $17 million consists of $1 million, $4 million and $12 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 September 30, 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.

21. 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.

Exelon has nine reportable segments, which include 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 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, and as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO and BGE's CODMs evaluate the performance of and allocate resources to ComEd, PECO and BGE based on net income and return on equity.

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned to these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, 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:
    - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
    - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
    - Canada represents operations across the entire country of Canada and includes 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 (RNF). Generation believes that RNF is a useful measurement of operational performance. RNF is not a presentation defined under GAAP and may not be comparable to other companies' presentations or deemed more useful than the GAAP information provided elsewhere in this report. Generation's operating revenues include all sales to third parties and affiliated sales to ComEd, PECO, and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation's owned generation and fuel costs associated with tolling agreements. The results of Generation's other business activities are not regularly reviewed by the CODM and are therefore not classified as operating segments or included in the regional reportable segment amounts. These activities include natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, Generation's unrealized mark-to-market gains and losses on economic hedging activities and its amortization of certain intangible assets and liabilities relating to commodity contracts recorded at fair value from mergers and acquisitions are also not included in the regional reportable segment amounts. 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.

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

An analysis and reconciliation of the Registrants' reportable segment information to the respective information in the consolidated financial statements is as follows:

Three Months Ended September 30, 2015 and 2014

	Generation[a]	ComEd	PECO	BGE	Other[b]	Intersegment Eliminations	Exelon
Total revenues[c]:							
2015	$ 4,768	$ 1,376	$ 740	$ 725	$ 348	$ (556)	$ 7,401
2014	4,412	1,222	693	697	305	(417)	6,912
Intersegment revenues[d]:							
2015	$ 205	$ 1	$ 1	$ 3	$ 347	$ (555)	$ 2
2014	112	1	—	3	302	(418)	—
Net income (loss):							
2015	$ 332	$ 149	$ 90	$ 54	$ (36)	$ (2)	$ 587
2014	849	126	81	49	(31)	—	1,074
Total assets:							
September 30, 2015	$ 46,479	$26,129	$10,072	$8,134	$16,256	$ (11,942)	$95,128
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 September 30, 2015 include revenue from sales to PECO of $61 million and sales to BGE of $141 million in the Mid-Atlantic region, and sales to ComEd of $2 million in the Midwest. For the three months ended September 30, 2014, intersegment revenues for Generation include revenue from sales to PECO of $28 million and sales to BGE of $83 million in the Mid-Atlantic region, and sales to ComEd of $1 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 September 30, 2015 and 2014, utility taxes of $28 million and $22 million, respectively, are included in revenues and expenses for Generation. For the three months ended September 30, 2015 and 2014, utility taxes of $63 million and $61 million, respectively, are included in revenues and expenses for ComEd. For the three months ended September 30, 2015 and 2014, utility taxes of $37 million and $34 million, respectively, are included in revenues and expenses for PECO. For the three months ended September 30, 2015 and 2014, utility taxes of $23 million and $21 million, respectively, are included in revenues and expenses for BGE.

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

(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with 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.

Generation total revenues:

	Three Months Ended September 30, 2015			Three Months Ended September 30, 2014		
	Revenues from External Customers[a]	Intersegment Revenues	Total Revenues	Revenues from External Customers[a]	Intersegment Revenues	Total Revenues
Mid-Atlantic	$ 1,622	$ 10	$ 1,632	$ 1,285	$ 4	$ 1,289
Midwest	1,150	1	1,151	1,062	(1)	1,061
New England	519	1	520	272	—	272
New York	254	(4)	250	230	2	232
ERCOT	317	(1)	316	303	(1)	302
Other Power Regions[b]	383	(7)	376	381	(6)	375
Total Revenues for Reportable Segments	4,245	—	4,245	3,533	(2)	3,531
Other[c]	523	—	523	879	2	881
Total Generation Consolidated Operating Revenues	$ 4,768	$ —	$ 4,768	$ 4,412	$ —	$ 4,412

(a) Includes all electric sales to third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other Power Regions includes the South, West and Canada.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $3 million decrease to revenues and a $22 million decrease to revenues for the amortization of intangible assets related to commodity contracts for the three months ended September 30, 2015 and 2014, respectively, unrealized mark-to-market losses of $7 million and gains of $271 million for the three months ended September 30, 2015 and 2014, respectively, and the elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense:

	Three Months Ended September 30, 2015			Three Months Ended September 30, 2014		
	RNF from External Customers[a]	Intersegment RNF	Total RNF	RNF from External Customers[a]	Intersegment RNF	Total RNF
Mid-Atlantic	$ 974	$ 17	$ 991	$ 921	$ 14	$ 935
Midwest	752	—	752	722	(6)	716
New England	145	(12)	133	120	(30)	90
New York	159	8	167	176	10	186
ERCOT	166	(55)	111	186	(77)	109
Other Power Regions[b]	167	(84)	83	157	(89)	68
Total Revenues net of purchased power and fuel for Reportable Segments	2,363	(126)	2,237	2,282	(178)	2,104
Other[c]	(114)	126	12	250	178	428
Total Generation Revenues net of purchased power and fuel expense	$ 2,249	$ —	$2,249	$ 2,532	$ —	$2,532

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

(a) Includes purchases and sales from third parties and affiliated sales to ComEd, PECO and BGE.
(b) Other Power Regions includes the South, West and Canada.
(c) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $4 million decrease to RNF and a $15 million increase to RNF for the amortization of intangible assets related to commodity contracts for the three months ended September 30, 2015 and 2014, respectively, unrealized mark-to-market losses of $139 million and gains of $267 million for the three months ended September 30, 2015 and 2014, respectively, and the elimination of intersegment revenues.

Nine Months Ended September 30, 2015 and 2014

	Generation[(a)]	ComEd	PECO	BGE	Other[(b)]	Intersegment Eliminations	Exelon
Total revenues[(c)]:							
2015	$ 14,841	$3,709	$2,386	$2,388	$1,007	$ (1,585)	$22,746
2014	12,591	3,484	2,343	2,404	924	(1,573)	20,173
Intersegment revenues[(d)]:							
2015	$ 567	$ 3	$ 1	$ 10	$1,003	$ (1,581)	$ 3
2014	630	2	1	21	920	(1,574)	—
Net income (loss):							
2015	$ 1,208	$ 339	$ 299	$ 212	$ (96)	$ (3)	$ 1,959
2014	1,037	335	255	156	(58)	—	1,725

(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 nine months ended September 30, 2015 include revenue from sales to PECO of $173 million and sales to BGE of $376 million in the Mid-Atlantic region, and sales to ComEd of $17 million in the Midwest. For the nine months ended September 30, 2014, intersegment revenues for Generation include revenue from sales to PECO of $165 million and sales to BGE of $290 million in the Mid-Atlantic region, and sales to ComEd of $175 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 nine months ended September 30, 2015 and 2014, utility taxes of $79 million and $67 million, respectively, are included in revenues and expenses for Generation. For the nine months ended September 30, 2015 and 2014, utility taxes of $180 million and $180 million, respectively, are included in revenues and expenses for ComEd. For the nine months ended September 30, 2015 and 2014, utility taxes of $104 million and $99 million, respectively, are included in revenues and expenses for PECO. For the nine months ended September 30, 2015 and 2014, utility taxes of $67 million and $64 million, respectively, are included in revenues and expenses for BGE.
(d) Intersegment revenues exclude sales to unconsolidated affiliates. The intersegment profit associated with 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.

Generation total revenues:

	Nine Months Ended September 30, 2015			Nine Months Ended September 30, 2014		
	Revenues from External Customers[(b)]	Intersegment Revenues	Total Revenues	Revenues from External Customers[(b)]	Intersegment Revenues	Total Revenues
Mid-Atlantic[(a)]	$ 4,475	$ 16	$ 4,491	$ 3,998	$ (14)	$ 3,984
Midwest	3,630	3	3,633	3,302	11	3,313
New England	1,743	3	1,746	1,028	5	1,033
New York[(a)]	786	(8)	778	614	(1)	613
ERCOT	691	(4)	687	743	(2)	741
Other Power Regions[(c)]	891	(11)	880	1,027	(4)	1,023

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

	Nine Months Ended September 30, 2015			Nine Months Ended September 30, 2014		
	Revenues from External Customers(b)	Intersegment Revenues	Total Revenues	Revenues from External Customers(b)	Intersegment Revenues	Total Revenues
Total Revenues for Reportable Segments	12,216	(1)	12,215	10,712	(5)	10,707
Other(d)	2,625	1	2,626	1,879	5	1,884
Total Generation Consolidated Operating Revenues	$ 14,841	$ —	$14,841	$ 12,591	$ —	$12,591

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, CENG's revenues are included 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 includes the South, West and Canada.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $19 million increase to revenues and a $203 million decrease to revenues for the amortization of intangible assets related to commodity contracts for the nine months ended September 30, 2015 and 2014, respectively, unrealized mark-to-market gains of $171 million and losses of $572 million for the nine months ended September 30, 2015 and 2014, respectively, and elimination of intersegment revenues.

Generation total revenues net of purchased power and fuel expense:

	Nine Months Ended September 30, 2015			Nine Months Ended September 30, 2014		
	RNF from External Customers(b)	Intersegment RNF	Total RNF	RNF from External Customers(b)	Intersegment RNF	Total RNF
Mid-Atlantic(a)	$ 2,633	$ 30	$2,663	$ 2,610	$ (60)	$2,550
Midwest	2,198	(3)	2,195	1,856	21	1,877
New England	416	(37)	379	362	(72)	290
New York(a)	471	27	498	289	24	313
ERCOT	344	(109)	235	457	(207)	250
Other Power Regions(c)	403	(210)	193	465	(216)	249
Total Revenues net of purchased power and fuel expense for Reportable Segments	6,465	(302)	6,163	6,039	(510)	5,529
Other(d)	576	302	878	(519)	510	(9)
Total Generation Revenues net of purchased power and fuel expense	$ 7,041	$ —	$7,041	$ 5,520	$ —	$5,520

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, starting on April 1, 2014, CENG's revenue net of purchased power and fuel expense are included 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 includes the South, West and Canada.
(d) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $20 million increase to RNF and a $78 million decrease to RNF for the amortization of intangible assets related to commodity contracts for the nine months ended September 30, 2015 and 2014, respectively, unrealized mark-to-market gains of $258 million and losses of $477 million for the nine months ended September 30, 2015 and 2014, respectively, and the elimination of intersegment revenue net of purchased power and fuel expense.

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 21 — 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.

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Executive Overview

Financial Results. The following consolidated financial results reflect the results of Exelon for the three and nine months ended September 30, 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 September 30,							Favorable (Unfavorable) Variance
	2015						2014	
	Generation[a]	ComEd[c]	PECO[c]	BGE[c]	Other	Exelon[a]	Exelon	
Operating revenues	$ 4,768	$ 1,376	$ 740	$ 725	$(208)	$ 7,401	$6,912	$ 489
Purchased power and fuel	2,519	390	278	311	(207)	3,291	2,648	(643)
Revenue net of purchased power and fuel[b]	2,249	986	462	414	(1)	4,110	4,264	(154)
Other operating expenses								
Operating and maintenance	1,241	404	196	169	(14)	1,996	1,982	(14)
Depreciation and amortization	264	176	68	79	19	606	577	(29)
Taxes other than income	123	79	44	57	7	310	306	(4)
Total other operating expenses	1,628	659	308	305	12	2,912	2,865	(47)
Equity in earnings of unconsolidated affiliates	—	—	—	—	—	—	1	(1)
Gain on sales of assets	1	—	—	1	—	2	338	(336)
Operating income (loss)	622	327	154	110	(13)	1,200	1,738	(538)
Other income and (deductions)								
Interest expense, net	(68)	(83)	(28)	(25)	(49)	(253)	(258)	5
Other, net	(257)	4	1	4	4	(244)	16	(260)
Total other income and (deductions)	(325)	(79)	(27)	(21)	(45)	(497)	(242)	(255)
Income before income taxes	297	248	127	89	(58)	703	1,496	(793)
Income taxes	(36)	99	37	35	(20)	115	422	307
Equity in losses of unconsolidated affiliates	(1)	—	—	—	—	(1)	—	(1)
Net income (loss)	332	149	90	54	(38)	587	1,074	(487)
Net income (loss) attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(45)	—	—	3	—	(42)	81	123
Net income (loss) attributable to common shareholders	$ 377	$ 149	$ 90	$ 51	$ (38)	$ 629	$ 993	$ (364)

	Nine Months Ended September 30, 2015						2014	Favorable (Unfavorable) Variance
	Generation[a]	ComEd[c]	PECO[c]	BGE[c]	Other	Exelon[a]	Exelon	
Operating revenues	$ 14,841	$ 3,709	$ 2,386	$ 2,388	$ (578)	$ 22,746	$ 20,173	$ 2,573
Purchased power and fuel	7,800	991	953	1,037	(571)	10,210	9,399	(811)
Revenue net of purchased power and fuel[b]	7,041	2,718	1,433	1,351	(7)	12,536	10,774	1,762
Other operating expenses								
Operating and maintenance	3,860	1,166	609	499	(15)	6,119	6,005	(114)
Depreciation and amortization	774	528	198	271	47	1,818	1,732	(86)
Taxes other than income	369	225	125	169	20	908	887	(21)
Total other operating expenses	5,003	1,919	932	939	52	8,845	8,624	(221)
Equity in losses of unconsolidated affiliates	—	—	—	—	—	—	(20)	20
Gain on sales of assets	7	—	1	1	1	10	356	(346)
Gain on consolidation and acquisition of businesses	—	—	—	—	—	—	261	(261)
Operating income (loss)	2,045	799	502	413	(58)	3,701	2,747	954
Other income and (deductions)								
Interest expense, net	(269)	(248)	(84)	(73)	(81)	(755)	(722)	(33)
Other, net	(193)	14	3	13	(16)	(179)	346	(525)
Total other income and (deductions)	(462)	(234)	(81)	(60)	(97)	(934)	(376)	(558)
Income (loss) before income taxes	1,583	565	421	353	(155)	2,767	2,371	396
Income taxes	371	226	122	141	(55)	805	646	(159)
Equity in earnings (loss) of unconsolidated affiliates	(4)	—	—	—	1	(3)	—	(3)
Net income (loss)	1,208	339	299	212	(99)	1,959	1,725	234
Net income attributable to noncontrolling interests, preferred security dividends and redemption and preference stock dividends	(10)	—	—	10	—	—	121	121
Net income (loss) attributable to common shareholders	$ 1,218	$ 339	$ 299	$ 202	$ (99)	$ 1,959	$ 1,604	$ 355

(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.

(c) For regulatory recovery mechanisms, including ComEd's distribution formula rate, ComEd and BGE's transmission formula rates, and riders across all utilities, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. Exelon's net income attributable to common shareholders was $629 million for the three months ended September 30, 2015 as compared to $993 million for the three months ended September 30, 2014, and diluted earnings per average common share were $0.69 for the three months ended September 30, 2015 as compared to $1.15 for the three months ended September 30, 2014.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, decreased by $154 million for the three months ended September 30, 2015 as compared to the same period in 2014. The quarter-over-quarter decrease in operating revenue net of purchased power and fuel expense was primarily due to the following unfavorable factors:

- Decrease of $406 million at Generation due to mark-to-market losses of $139 million in 2015 from economic hedging activities as compared to $267 million in mark-to-market gains in 2014;
- Decrease of $19 million at Generation related to amortization of energy contracts recorded at fair value during prior acquisitions;

The quarter-over-quarter decrease in revenue net of purchased power and fuel expense was partially offset by the following favorable factors:

- Increase of $142 million at Generation primarily due the benefit of lower cost to serve load, the inclusion of Integrys' results in 2015, and increased load served; partially offset by lower margins and capacity revenues resulting from the absence of generating assets sold in 2014;
- Increase of $90 million at ComEd primarily due to increased electric distribution and transmission formula rate revenue resulting from increased capital investments and an increase in fully recoverable costs and favorable weather, partially offset by lower electric distribution ROE due to a decrease in treasury rates;
- Increase of $24 million at PECO primarily due to favorable weather; and
- Increase of $14 million at BGE primarily due to increased distribution revenue as a result of the December 2014 electric and natural gas distribution rate case order issued by the Maryland PSC and an increase in fully recoverable costs.

Operating and maintenance expense increased by $14 million for the three months ended September 30, 2015 as compared to the same period in 2014 primarily due to the following favorable factors:

- Increase in Generation's labor, contracting and materials costs of $45 million;
- An increase in pension and non-pension postretirement benefits expense of $19 million as a result the unfavorable impact of lower assumed pension and OPEB discount rates for 2015 and an increase in the life expectancy assumption for plan participants in 2015; and
- Increased fully recoverable energy efficiency program costs at ComEd of $21 million.

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

- Long-lived asset impairments of $49 million in 2014; and
- Merger and integration costs of $46 million in 2015 as compared to $70 million in 2014.

Depreciation and amortization expense increased by $29 million primarily related to ongoing capital expenditures across all registrants.

Taxes other than income remained relatively flat quarter-over-quarter.

Gain on sales of assets decreased by $336 million primarily due to the gain on sale of Safe Harbor Water Corporation recorded in 2014.

Interest expense decreased by $5 million primarily as a result of the favorable settlement in 2015 of an income tax position on Constellation's pre-acquisition tax returns at Generation, partially offset by higher outstanding debt at Generation and Corporate.

Other, net decreased by $260 million primarily as a result of the change in realized and unrealized gains and losses on NDT fund investments at Generation.

Equity in losses of unconsolidated affiliates remained relatively flat quarter-over-quarter.

Exelon's effective income tax rates for the three months ended September 30, 2015 and 2014 were 16.4% and 28.2%, respectively. See Note 12 — 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 September 30, 2015, including explanation of the non-GAAP measure of revenue net of purchased power and fuel expense, see the discussions of Results of Operations by Segment below.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. Exelon's net income attributable to common shareholders was $1,959 million for the nine months ended September 30, 2015 as compared to $1,604 million for the nine months ended September 30, 2014, and diluted earnings per average common share were $2.22 for the nine months ended September 30, 2015 as compared to $1.86 for the nine months ended September 30, 2014.

Operating revenue net of purchased power and fuel expense, which is a non-GAAP measure discussed below, increased by $1,762 million for the nine months ended September 30, 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 $692 million at Generation primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015, a reduction in the number of nuclear outage days in 2015, the inclusion of Integrys' results in 2015, the benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), the cancellation of the DOE spent nuclear fuel disposal fee, increased capacity prices, favorability from portfolio management optimization activities, and increased load served, partially offset by lower margins and capacity revenues resulting from the absence of generating assets sold in 2014, lower realized energy prices and the absence of fuel optimization opportunities realized in 2014 in the South;
- Increase of $98 million at Generation related to amortization of contracts recorded at fair value during prior acquisitions;
- Increase of $735 million at Generation due to mark-to-market gains of $258 million in 2015 from economic hedging activities as compared to $477 million in mark-to-market losses in 2014;
- Increase of $149 million at ComEd primarily due to increased electric distribution and transmission formula rate revenues due to increased capital investments and an increase in fully recoverable costs, partially offset by lower electric distribution ROE due to a decrease in treasury rates;
- Increase of $50 million at PECO primarily due to favorable weather and volume; and
- Increase of $41 million at BGE primarily due to increased distribution revenue as a result of the December 2014 electric and natural gas distribution rate case order issued by the Maryland PSC.

Operating and maintenance expense increased by $114 million for the nine months ended September 30, 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 $202 million primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015;
- An increase in the costs associated with number of planned nuclear refueling outage days, including Salem and the CENG plants, at Generation of $8 million.
- An increase in pension and non-pension postretirement benefits expense of $26 million as a result the unfavorable impact of lower assumed pension and OPEB discount rates for 2015 and an increase in the life expectancy assumption for plan participants in 2015, partially offset by cost savings from plan design changes for certain OPEB plans effective April 2014 and forward;
- Increase in labor, contracting and materials of $38 million at ComEd due to increased contracting costs related to preventative maintenance and other projects; and
- Increased fully recoverable costs associated with uncollectible accounts at ComEd of $37 million.

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

- Long-lived asset impairments of $24 million in 2015 compared to $162 million in 2014;
- Decreased storm costs at PECO and BGE of $78 million and $23 million, respectively;
- Decreased uncollectible accounts expense at BGE of $23 million; and
- A benefit in 2015 of $14 million for the favorable settlement of a long-term railcar lease agreement pursuant to the Midwest Generation bankruptcy.

Depreciation and amortization expense increased by $86 million primarily as a result of the inclusion of CENG's results on a fully consolidated basis in 2015 at Generation and ongoing capital expenditures across all registrants.

Taxes other than income increased by $21 million primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015.

Equity in earnings of unconsolidated affiliates increased by $17 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 losses in 2015.

Gains on sales of assets decreased by $346 million primarily due to the gain on sale of Safe Harbor Water Corporation recorded in 2014.

Gain on consolidation and acquisition of businesses decreased by $261 million due to the gain recorded upon the consolidation of CENG in 2014, resulting from the difference in the fair value of CENG's net assets as of April 2014, and the equity method investment previously recorded on Generation's and Exelon's books and the settlement of pre-existing transactions between Generation and CENG.

Interest expense increased by $33 million primarily as a result of higher outstanding debt at Generation and Exelon Corporate, and financing agreements related to the pending PHI merger at Exelon Corporate, partially offset by mark-to-market gains recorded in 2015 on forward-starting interest rate swaps related to the financing of the pending PHI merger recorded at Exelon Corporate as compared to losses recorded in 2014 and the favorable settlement in 2015 of an income tax position on Constellation's pre-acquisition tax returns at Generation.

Other, net decreased by $525 million primarily as a result of the change in realized and unrealized gains and losses on NDT fund investments at Generation, favorable settlements in 2014 of certain income tax positions on Constellation's pre-acquisition tax returns and a loss of $26 million on the termination of forward-starting interest rate swaps in 2015 at Exelon Corporate.

Exelon's effective income tax rates for the nine months ended September 30, 2015 and 2014 were 29.1% and 27.2%, respectively. See Note 12 — 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 nine months ended September 30, 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 September 30, 2015 were $757 million, or $0.83 per diluted share, compared with adjusted (non-GAAP) operating earnings of $676 million, or $0.78 per diluted share for the same period in 2014. Exelon's adjusted (non-GAAP) operating earnings for the nine months ended September 30, 2015 were $1,880 million, or $2.13 per diluted share, compared with adjusted (non-GAAP) operating earnings of $1,646 million, or $1.91 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.

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 and nine months ended September 30, 2015 as compared to the same period in 2014. The footnotes below the table provide tax expense (benefit) impacts:

	Three Months Ended September 30,			
	2015		2014	
(All amounts after tax)		Earnings per Diluted Share		Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$629	$ 0.69	$ 993	$ 1.15
Mark-to-Market Impact of Economic Hedging Activities[(a)]	85	0.09	(158)	(0.18)
Unrealized Losses Related to NDT Fund Investments[(b)]	133	0.15	22	0.03
Asset Retirement Obligation[(c)]	(6)	(0.01)	(13)	(0.02)
Plant Retirements and Divestitures[(d)]	—	—	(197)	(0.23)
Long-Lived Asset Impairment[(e)]	—	—	30	0.03
Merger and Integration Costs[(f)]	12	0.02	58	0.06
Amortization of Commodity Contract Intangibles[(g)]	2	—	(12)	(0.01)
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps[(h)]	—	—	6	0.01
Tax Settlements[(i)]	(52)	(0.06)	(66)	(0.08)
CENG Noncontrolling Interest[(j)]	(46)	(0.05)	13	0.02
Adjusted (non-GAAP) Operating Earnings	$757	$ 0.83	$ 676	$ 0.78

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(All amounts after tax)	Nine Months Ended September 30, 2015	Earnings per Diluted Share	2014	Earnings per Diluted Share
Net Income Attributable to Common Shareholders	$1,959	$ 2.22	$1,604	$ 1.86
Mark-to-Market Impact of Economic Hedging Activities[(a)]	(158)	(0.18)	293	0.34
Unrealized (Gains) Losses Related to NDT Fund Investments[(b)]	164	0.19	(62)	(0.07)
Asset Retirement Obligation[(c)]	(6)	(0.01)	(13)	(0.02)
Plant Retirements and Divestitures[(d)]	—	—	(197)	(0.23)
Impairment of Long Lived Assets[(e)]	15	0.02	98	0.11
Merger and Integration Costs[(f)]	50	0.06	99	0.11
Amortization of Commodity Contract Intangibles[(g)]	(13)	(0.01)	42	0.06
Mark-to-Market Impact of PHI Merger Related Interest Rate Swaps[(h)]	(21)	(0.03)	6	0.01
Tax Settlements[(i)]	(52)	(0.06)	(101)	(0.12)
Gain on CENG Integration[(k)]	—	—	(159)	(0.18)
Midwest Generation Bankruptcy Recoveries[(l)]	(6)	(0.01)	—	—
CENG Noncontrolling Interest[(j)]	(52)	(0.06)	36	0.04
Adjusted (non-GAAP) Operating Earnings	$1,880	$ 2.13	$1,646	$ 1.91

(a) Reflects the impact of (gains) losses for the three months ended September 30, 2015 and September 30, 2014 (net of taxes of $54 million and $105 million, respectively) and the nine months ended September 30, 2015 and September 30, 2014 (net of taxes of $101 million and $188 million, respectively) on Generation's economic hedging activities. See Note 10 — 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 Non-Regulatory Agreement Units and the contractual offset for taxes related to Regulatory Agreement Units and Pledged Assets for the three months ended September 30, 2015 and September 30, 2014 (net of taxes of $148 million and $25 million, respectively) and the nine months ended September 30, 2015 and September 30, 2014 (net of taxes of $193 million and $22 million, respectively) on Generation's NDT fund investments. See Note 13 — Nuclear Decommissioning of the Combined Notes to Consolidated Financial Statements for additional detail related to Generation's NDT fund investments.

(c) Reflects the impacts of a non-cash benefit pursuant to the annual update of Generation's decommissioning obligation for the three and nine months ended September 30, 2015 and September 30, 2014 (net of taxes of $4 million for all periods).

(d) Reflects the impact associated with the sale or retirement of Generation's ownership interest in generating stations for the three and nine months ended September 30, 2014 (net of taxes of $132 million).

(e) Reflects the 2015 charge to earnings for the nine months ended September 30, 2015 related to the impairment of investment in long-term leases (net of taxes of $9 million) and 2014 charges to earnings for the three and nine months ended September 30, 2014 related to the impairment of certain wind generating assets, certain generating assets held for sale, and investment in long-term leases (net of taxes of $20 million and $18 million, respectively).

(f) Reflects certain costs incurred for the three months ended September 30, 2015 and September 30, 2014 (net of taxes of $9 million and $20 million, respectively) and the nine months ended September 30, 2015 and September 30, 2014 (net of taxes of $32 million and $30 million, respectively) associated with the Constellation merger, pending PHI acquisition, and, at Generation, the CENG integration, including professional fees, employee-related expenses, integration activities, upfront credit facilities fees, merger commitments, and certain pre-acquisition contingencies.

(g) Reflects the non-cash impact for the three months ended September 30, 2015 and September 30, 2014 (net of taxes of $2 million and $2 million, respectively) and the nine months ended September 30, 2015 and September 30, 2014 (net of taxes of $7 million and $44 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.

(h) Reflects the impact of losses (gains) on forward-starting interest rate swaps at Exelon Corporate related to financing of the pending PHI acquisition for the nine months ended September 30, 2015 (net of taxes of $14 million) and the three and nine months ended September 30, 2014 (net of taxes of $4 million for both periods) .

(i) Reflects a benefit related to the favorable settlement of certain income tax positions on Constellation's pre-acquisition tax returns for the three months ended September 30, 2015 and September 30, 2014 (inclusive of taxes of $41 million and $52 million, respectively) and the nine months ended September 30, 2015 and September 30, 2014 (inclusive of taxes of $41 million and $70 million, respectively).

(j) 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 in 2015, and in 2014 the impact of unrealized gains and losses on NDT fund investments, certain merger and acquisition costs, and non-cash amortization of intangible assets, net, related to commodity contracts.

(k) Reflects the non-cash gain recorded upon consolidation of CENG in accordance with the execution of the NOSA on April 1, 2014 for the nine months ended September 30, 2014 (net of taxes of $103 million).

(l) Reflects a benefit related to the favorable settlement of a long term lease agreement pursuant to the Midwest Generation bankruptcy for the nine months ended September 30, 2015 (net of taxes of $4 million).

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.

For the three and nine months ended September 30, 2015 and 2014, expense has been recognized for costs incurred to achieve the Constellation merger, CENG integration and the Integrys and pending PHI acquisitions as follows:

	Pre-tax Expense Three Months Ended September 30, 2015				
Merger, Integration and Acquisition Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Transaction[(a)]	$ —	$ —	$ —	$ —	$ 5
Other[(b)]	10	3	1	2	17
Total	$ 10	$ 3	$ 1	$ 2	$ 22

	Pre-tax Expense Three Months Ended September 30, 2014				
Merger and Integration Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Financing[(c)]	$ —	$ —	$ —	$ —	$ 11
Regulatory Commitments[(d)]	44	—	—	—	44
Other[(b)]	18	—	—	—	23
Total	$ 62	$ —	$ —	$ —	$ 78

	Pre-tax Expense Nine Months Ended September 30, 2015				
Merger, Integration and Acquisition Costs:	**Generation**	**ComEd**	**PECO**	**BGE**	**Exelon**
Transaction[(a)]	$ —	$ —	$ —	$ —	$ 14
Financing[(c)]	—	—	—	—	21
Other[(b)]	30	9	4	4	49
Total	$ 30	$ 9	$ 4	$ 4	$ 84

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Merger and Integration Costs:	Pre-tax Expense Nine Months Ended September 30, 2014 Generation	ComEd	PECO	BGE	Exelon
Financing[c]	$ —	$ —	$ —	$—	$ 20
Regulatory Commitments[d]	44	—	—	—	44
Employee-Related[e]	5	—	—	—	5
Other[b]	43	—	—	—	60
Total	$ 92	$ —	$ —	$—	$ 129

(a) 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.
(b) Costs to integrate CENG and Constellation processes and systems into Exelon and to terminate certain Constellation debt agreements. For the three and nine months ended September 30, 2015, also includes professional fees primarily related to integration for the proposed PHI acquisition.
(c) Reflects (benefits) costs recorded at Exelon related to the financing of the PHI merger, including upfront credit facility fees. Excludes mark-to-market activity on forward-starting interest rate swaps.
(d) Reflects costs incurred at Generation for a Constellation merger commitment.
(e) Costs primarily for employee severance, pension and OPEB expense and retention bonuses.

As of September 30, 2015, Exelon projects incurring total PHI acquisition and integration related costs over the next five years of approximately $635 million, excluding the amounts Exelon and PHI are committed, if approved, to provide to the PHI utility's respective customers. Included in this amount are costs to fund the acquisition of which $66 million has been paid and recorded as deferred debt issuance costs and $60 million has been incurred and charged to common stock. Also included is approximately $100 million for integration costs expected to be capitalized to Property, plant and equipment. Including 2014 and through September 30, 2015, Exelon has incurred approximately $226 million of expense associated with the proposed merger. The remaining costs will be primarily within Operating and maintenance expense within Exelon's Consolidated Statements of Operations and Comprehensive Income.

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 for office space 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 by the end of 2016. See Note 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for further information related to the lease commitments.

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.

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 to reduce earnings volatility. Generation leverages its energy generation portfolio to deliver energy to both wholesale and retail customers. 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. Additionally, ComEd, PECO and BGE anticipate making significant future investments 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 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. Based on the outstanding shares of PHI's common stock as of September 30, 2015, PHI shareholders would receive $6.9 billion in total cash. In addition, in connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $180 million of a class of nonvoting, nonconvertible and nontransferable preferred securities of PHI. 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.

On September 9, 2014, Exelon and PHI filed a Notification and Report Form with DOJ under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act). 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. Under the HSR Act, if the merger is not completed before December 23, 2015, Exelon and PHI are required to file again under the HSR Act and observe the required waiting periods, which is a minimum of 30 days from the new filing (and longer if the DOJ requests additional information), unless the DOJ terminates the waiting period earlier. Exelon and PHI may refile under the HSR Act in advance of December 23, 2015.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU), the Delaware Public Service Commission (DPSC), the Maryland Public Service Commission (MDPSC) 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 NJBPU approved the proposed merger and the previously filed settlement signed and filed by Exelon, PHI, Atlantic City Electric (ACE), NJBPU staff, and the Independent Energy Coalition. The settlement provides a package of benefits to ACE customers and the state of New Jersey. This package of benefits includes the establishment of customer rate credit programs, with an aggregate value of $62 million for ACE customers and energy efficiency programs that will provide savings for ACE customers of $15 million. The March 6, 2015, order by the NJBPU approving the merger required that the consummation of the merger must take place no later than November 1, 2015 unless otherwise extended by the Board. On October 15, 2015, the NJBPU extended the November 1, 2015 date to June 30, 2016.

On February 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, 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 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 June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

On March 17, 2015, Exelon and PHI announced that they had reached settlements with multiple parties in the Maryland proceeding to review the proposed merger after filing a Request for Adoption of Settlements with the MDPSC. The settlements were signed and filed by Exelon, PHI, Montgomery County, Prince George's County, The Alliance for Solar Choice, the National Consumer Law Center, National Housing Trust, the 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. On May 15, 2015, the MDPSC approved the merger after modifying a number of the conditions in the settlements, resulting in total rate credits of $66 million, funding for energy efficiency programs of $43.2 million, a Green Sustainability Fund of $14.4 million, 20 MWs of renewable generation development, ring-fencing, financial reporting conditions and increased penalties related to reliability commitments. On May 18, 2015, Exelon and PHI accepted and committed to fulfill the conditions.

On June 11, 2015, the Maryland Office of People's Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC's approval of the merger with the Circuit Court for Queen Anne's County. On June 23, 2015, Public Citizen, Inc. filed its Petition for Judicial Review with the Circuit Court for Queen Anne's County. On July 10, 2015, Exelon and PHI filed a response in opposition to the Petitions for Review.

On July 21, 2015, the OPC filed a motion to stay the MDPSC order approving the merger and to set a schedule for discovery and presentation of new evidence. On July 29, 2015, Public Citizen, Inc. filed a response supporting OPC's motion to stay, and on July 31, 2015 the Sierra Club and the Chesapeake Climate Action Network filed a joint motion to stay. In July and August, Exelon, PHI, the MDPSC, Prince George's County and Montgomery County filed responses opposing the motions to stay. The presiding judge issued an order denying the motions for stay on August 12, 2015. A hearing on the underlying Petitions for Review is scheduled for December 8, 2015.

On August 27, 2015, the District of Columbia Public Service Commission (DCPSC) issued an Opinion and Order denying approval of the merger, asserting that the merger was not in the public's interest. Exelon and PHI filed an Application for Reconsideration with the DCPSC on September 28, 2015. On October 6, 2015, Exelon, PHI, the District of Columbia Government, the Office of Peoples Counsel, the District of Columbia Water and Sewer Authority, the National Consumer Law Center, National Housing Trust and National Housing Trust — Enterprise Preservation Corporation, and the Apartment and Office Building Association of Metropolitan Washington (collectively, Settling Parties) entered into a Nonunanimous Full Settlement Agreement and Stipulation (Settlement Agreement) with respect to the merger. Exelon and PHI subsequently filed a motion of joint applicants requesting the DCPSC to reopen the approval application to allow for consideration of the Settlement Agreement and granting additional requested relief. The new package of benefits totals $78 million and includes commitments to provide relief of residential customer base rate increases of $26 million, one-time direct bill credits of $14 million, low-income energy assistance of $16 million, improved reliability, a cleaner and greener D.C. through funding energy efficiency programs and development of renewable energy, and investment in local jobs and the local economy through workforce development of $5 million. It also guarantees charitable contributions totaling $19 million over 10 years.

On October 28, 2015, the DCPSC at a public meeting agreed to reopen the approval application to allow for consideration of the Settlement Agreement and set a procedural schedule which would allow for completion of the merger in the first quarter of 2016. If the DCPSC does not approve the Settlement Agreement within the 150 day period after it was filed, either Exelon or PHI may terminate the Settlement Agreement.

The settlements reached and commission orders received to date in Delaware, Maryland and New Jersey include a "most favored nation" provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions. When applying the most favored nation provision to the settlement terms and other conditions established in the merger approvals received to date, and as proposed in the Settlement Agreement filed with the DCPSC, Exelon and PHI currently estimate direct benefits of $430 million or more on a net present value basis (excluding charitable contributions and renewable generation commitments) will be provided, including rate credits, funding for energy efficiency programs, sustainability funds and other required commitments. Exelon and PHI anticipate substantially all of such amounts will be charged to earnings at the time of merger close and will be paid by the end of 2017. An additional $50 million will be charged to earnings for charitable contributions, which are required to be paid over a period of 10 years. Commitments to develop renewable generation, which are expected to be primarily capital in nature, will be recognized as incurred. Upon completion of the merger, the actual nature, amount, timing and financial reporting treatment for these commitments may be materially different from the current projection.

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 September 30, 2015, Exelon has incurred approximately $226 million of expense associated with the proposed merger. Of the total costs incurred, $110 million is primarily related to acquisition and integration costs and $116 million is for costs incurred to finance the transaction. The financing costs include a net loss of $64 million related to the settlement of forward-starting interest-rate swaps. These swaps were terminated in connection with the $4.2 billion issuance of debt; refer to Note 10—Derivative Financial Instruments and Note 11— Debt and Credit Agreements for more information. The financing costs exclude costs to issue debt and equity.

During the three months ended September 30, 2015, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs, including financing costs, of $21 million, $9 million, $3 million, $2 million and $2 million, respectively. During the nine months ended September 30, 2015, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs of $47 million, $24 million, $10 million, $4 million and $5 million, respectively.

During the three months ended September 30, 2014, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs, including financing costs, of $32 million, $3 million, $1 million, $1 million and $1 million, respectively. During the nine months ended September 30, 2014, Exelon, Generation, ComEd, PECO and BGE incurred acquisition and integration costs of $57 million, $4 million, $1 million,$1 million and $1 million, respectively.

The costs incurred are classified primarily within Operating and maintenance expense in the Registrants' respective Consolidated Statement of Operations and Comprehensive Income, with the exception of the financing costs, which are included within Interest expense.

The Merger Agreement also provides for termination rights for both parties. Exelon and PHI have entered into a Letter Agreement related to the Settlement Agreement which has the practical effect of suspending their rights to terminate the Merger Agreement until November 20, 2015 if no schedule has been set by the DCPSC allowing for approval of the settlement by March 4, 2016, or until March 4, 2016, if a schedule is set for approval by March 4, 2016, but approval does not occur by that date. 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 $180 million (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 reimbursement of PHIs documented out-of-pocket expenses up to a maximum of $40 million.

Merger Financing

As of September 30, 2015, through the issuance of $5.4 billion of debt (including $1.15 billion of junior subordinated notes in the form of 23 million equity units), the issuance of $1.9 billion of common stock, and cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion), Exelon has sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 11—Debt and Credit Agreements and Note 17—Common Stock for further information on the debt and equity issuances. See Note 4—Merger and Acquisitions of the Exelon 2014 Form 10-K for further information on the asset sales.

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. Refer to Note 4 — Mergers, Acquisitions, and Dispositions of the Combined Notes to Consolidated Financial Statements for additional information on the merger transaction.

Implications of Potential Early Plant Retirements

Exelon and Generation continue to evaluate the current and expected economic value of each of Generation's nuclear plants. Factors that will continue to affect the economic value of Generation's nuclear plants include, but are not limited to: market power prices, results of capacity auctions, potential legislative solutions in Illinois such as the proposed Low Carbon Portfolio Standard (LCPS) legislation, the impact of final rules from the U.S. EPA requiring reduction of carbon and other emissions and the efforts of the states to implement those final rules, and the outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions. On September 10, 2015, after considering the results of the recent PJM capacity auctions, Exelon and Generation decided to defer for one year any decisions about the future operations of its Quad Cities and Byron nuclear plants and will offer both plants in the 2019/2020 auction in May 2016. As a result of clearing the other PJM capacity auction in September 2015 for the 2017/2018 transitional capacity auction, Exelon and Generation will continue to operate its Quad Cities nuclear power plant through at least May 2018. The Byron plant is already obligated to operate through May 2019. In addition, on October 29, 2015, Exelon and Generation decided to defer any decision about the future operations of its Clinton nuclear plant for one year and plan to bid the plant into the MISO capacity auction for the 2016/2017 planning year in March 2016. MISO's announcement on October 27, 2015 acknowledging the need for market design changes in southern Illinois was a key factor in Exelon's and Generation's decision to defer for an additional year, among other factors such as positive results from the Illinois Power Agency's capacity procurement for 2016 and the long-term impact of the EPA's Clean Power Plan. The Clinton plant is currently obligated to operate through May 2016. Exelon and Generation previously committed to cease operation of the Oyster Creek nuclear plant by the end of 2019. Exelon and Generation have not made any decisions regarding potential nuclear plant closures at other sites at this time.

As a result of a decision to early retire one or more other nuclear plants, certain changes in accounting treatment would be triggered and Exelon's and Generation's results of operations and cash flows could be materially affected by a number of items including, among other items: accelerated depreciation expense, impairment charges related to inventory that cannot be used at other nuclear units and cancellation of in-flight capital projects, accelerated amortization of plant specific nuclear fuel costs, severance costs, accelerated asset retirement obligation expense related to future decommissioning activities, and additional funding of decommissioning costs. In addition, any early plant retirement would also result in reduced operating costs, lower fuel expense, and lower capital expenditures in the periods beyond shutdown. While there are a number of Generation's nuclear plants that are at risk of early retirement, the following table provides the balance sheet amounts as of September 30, 2015 for significant assets and liabilities associated with the three nuclear plants currently considered by management to be at the greatest risk of early retirement due to their current economic valuations and other factors:

(in millions)	Quad Cities	Clinton	Ginna	Total
Asset Balances				
Materials and supplies inventory	$ 49	$ 56	$ 30	$ 135
Nuclear fuel inventory, net	186	122	65	373
Completed plant, net	1,027	582	111	1,720
Construction work in progress	29	8	23	60
Liability Balances				
Asset retirement obligation	(696)	(396)	(637)	(1,729)
NRC License Renewal Term	2032	2046[(a)]	2029	

(a) Assumes Clinton seeks and receives a 20-year operating license renewal extension.

In the event a decision is made to early retire one or more nuclear plants, the precise timing of the retirement date, and resulting financial statement impact, is uncertain and would be influenced by a number of factors such as the results of any transmission system reliability study assessments, the nature of any co-owner requirements and stipulations, and decommissioning trust fund requirements, among other factors. However, the earliest retirement date for any plant would usually be the first year in which the unit does not have capacity obligations and just prior to its next scheduled nuclear refueling outage date in that year.

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 sought 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. Generation participated actively in PJM's stakeholder process through which PJM developed the proposal and also actively participated 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. On June 9, 2015, FERC approved PJM's filing largely as proposed by PJM, including transitional auction rules for delivery years 2016/2017 through 2017/2018. PJM also sought approval from the FERC to delay the 2018/2019 RPM Base Residual Auction that would otherwise have been conducted in May, 2015. On April 24, 2015, the FERC issued an order allowing the delay. As a result of these orders, PJM hosted its 2018/2019 Base Residual Auction (results posted on August 21, 2015) and its transitional auction for delivery year 2016/2017 (results posted on August 31, 2015) and its transitional auction for delivery years 2017/2018 (results posted on September 9, 2015).

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 zone 4 region in downstate Illinois increased to $150 MW per day beginning in June 2015, an increase from the prior pricing of $16.75 MW per day that was 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's and Generation's consolidated results of operations and cash flows.

In late May 2015, a separate complaint was filed at the FERC by each of the State of Illinois, the Southwest Electric Cooperative and Public Citizens, Inc., challenging the results of this MISO capacity auction for the 2015/2016 delivery in MISO delivery zone 4. The complaints allege generally that the results of the capacity auction for zone 4 are not just and reasonable, the results should be suspended, set for hearing and replaced with a new just and reasonable rate, a refund date should be established and that certain alleged behavior by one of the market participants be investigated. Generation had an offer that was selected in the auction. On October 1, 2015, the FERC announced that it was conducting a non-public investigation (that does not involve Exelon) into whether market manipulation of other potential violations occurred related to the auction. On October 20, 2015, the FERC held a technical conference to obtain further information related to the complaints. While it is too early to predict the outcome of the complaint proceeding, Generation's auction results could be impacted by its outcome.

Additionally, MISO acknowledged the need for capacity market design changes in the zone 4 region by posting an issues statement on October 27, 2015. MISO stated that reforms to its capacity market process may be required to drive future investment and that it plans to engage stakeholders to consider such reforms. See Note 8—Implications of Potential Early Plant Retirements for additional information on the impacts of the MISO announcement.

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 into 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 would be in commercial operation by June 1, 2015. CPV 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.

Exelon and others have challenged the constitutionality and other aspects of the New Jersey legislation and the actions taken by the MDPSC 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 MDPSC, respectively. However, the U.S. Supreme Court has agreed to review the matter, 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. 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 BGE, no growth for PECO; and a decrease in projected load for electricity for ComEd. BGE, PECO and ComEd are projecting load volumes to increase (decrease) by 0.5%, 0.0% and (0.7)%, 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's board of directors declared first, second, third and fourth quarter 2015 dividends of $0.31 per share each on Exelon's common stock. The dividends for the first, second and third quarter were paid on March 10, 2015, June 10, 2015 and September 10, 2015. The fourth quarter dividend is payable on December 10, 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 September 30, 2015, the percentage of expected generation hedged for the major reportable segments is 97%-100%, 81%-84% and 51%-54% 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.

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 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 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

Exelon is currently pursuing growth in both the utility and competitive energy businesses. Management continually evaluates growth opportunities aligned with Exelon's businesses, assets and markets, leveraging Exelon's expertise in those areas. By identifying and capitalizing on emerging trends, Exelon plans to invest in new innovative technologies to compete with a new breed of energy players, with the expectation of leveraging those technologies to improve productivity and efficiencies within our existing businesses.

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 investing approximately $16 billion over the next five years in electric and natural gas infrastructure improvements and modernization projects, including smart meter and smart grid initiatives, storm hardening, advanced reliability technologies, and transmission projects, which is projected to result in an increase to current rate base of approximately $9 billion by the end of 2019. ComEd, PECO and BGE invest in rate base where beneficial 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 and infrastructure development and enhancement programs.

Competitive Energy Businesses

Generation pursues growth in areas that take advantage of our existing core competencies. Generation continually assesses the optimal structure and composition of our generation assets as well as explore retail opportunities. Generation identifies emerging technologies where investments provide the option for significant future growth or influence in market development. As of September 30, 2015, Generation has currently approved plans to invest a total of $2.3 billion in 2015 (full year) through 2019 on capital growth projects (primarily new plant construction and distributed generation). Additional growth opportunities continue to arise across the energy value chain.

Leveraging its competencies,

- Generation's 2014 acquisition of Integrys and Proliance retail energy marketing businesses allows Generation to expand its electric and gas 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 prioritize investment opportunities in contracted generation across multiple technologies, including renewables.
- Generation has a growing business in distributed generation that capitalizes on the trend toward a decentralized system and an increasing customer preference for clean energy.
- The overall growth in natural gas supply is a key trend we expect to be sustained over the long term. Our upstream, midstream and LNG businesses will enable us to participate in that trend.

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 Exelon and Generation's 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.

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 secure sufficient liquidity or secure liquidity at reasonable terms. As of September 30, 2015, approximately 29%, or $2.5 billion, of the Registrants' aggregate total commitments were with European banks. The credit facilities include $8.5 billion in aggregate total commitments of which $6.8 billion was available as of September 30, 2015, due to outstanding letters of credit and commercial paper. There were no borrowings under the Registrants' credit facilities as of September 30, 2015. See Note 11 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for additional information on the credit facilities.

Tax Matters

See Note 12 — 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., NOx, SO2 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 issued on October 1, 2015. These recently finalized NAAQS updates will potentially result in more stringent emissions limits on fossil-fuel electric generating stations as states develop compliance plans and the U.S. EPA considers future regulation updates to address interstate air pollution.

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, the D.C. Circuit Court held that the 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. On November 21, 2014 the Agency proposed CSAPR allowance allocations to generating units for the first five years of the program, 2015- 2020. These allowances were identical to those previously set forth in prior CSAPR rules. On remand the D.C. Circuit Court is reviewing the residual CSAPR challenges not addressed by the U.S. Supreme Court decision. On May 26, 2015, the D.C. Circuit Court issued its opinion on one of the residual CSAPR challenges and denied petitions to review EPA's Kansas SIP disapproval, finding that the EPA had acted within the bounds of its delegated authority when it originally disapproved Kansas' proposed state implementation plans (SIP). On July 28, 2015 the D.C. Circuit Court released its opinion regarding the remaining challenges following the Supreme Court's 2014 decision. In the opinion, the D.C. Circuit found that the original 2014 emission budgets challenged by petitioners were invalid and remanded them to EPA without vacatur. Note that the "2014" budgets were tolled to the 2017 compliance periods by EPA to address time lost during the litigation process. The budgets remanded include: the SO2 budgets for Texas, Alabama, Georgia, and South Carolina; and the NOx emissions budgets for Florida, Maryland, New Jersey, New York, North Carolina, Ohio, Pennsylvania, South Carolina, Texas, Virginia and West Virginia. Additionally, the court rejected claims to several broader challenges to CSAPR and denied the petitions with respect to those issues. EPA is currently evaluating its options with regard to reconsideration of these budgets.

In addition, on September 29, 2015, U.S. EPA sent to the Office of Management and Budget a draft of its proposed Interstate Transport Rule update to address the 2008 ozone NAAQS.

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, and a number of retirements have already occurred. Coal units with existing controls that do not meet the MATS rule may need to upgrade existing controls or add new controls to comply. Owners of oil units not currently meeting the proposed emission standards may choose to convert the units to light oils or natural gas, install control technologies, or retire the units. Numerous entities 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. On June 28, 2015, the Supreme Court decided that the U.S. EPA unreasonably refused to consider costs in determining whether it is appropriate and necessary to regulate hazardous air pollutants emitted by electric utilities. The Court, however, did not vacate the rule; rather, it was remanded to the D.C. Circuit Court of Appeals to take further action consistent with the Supreme Court's opinion. As such, the rule remains in effect as of April 16, 2015; however, facilities may be granted an additional one or two year extension in limited cases. While it is possible that the D.C. Circuit Court will vacate or stay the rule, Exelon believes that the Supreme Court's concerns can be quickly addressed without vacating the rule and affecting the compliance schedule. Exelon will continue to participate in the remanded proceedings before the Circuit Court as an intervenor in support of the rule.

The U.S. EPA continued its regular, periodic review of the NAAQS standards, most recently issuing a revised ground-level ozone standard on October 1, 2015. The new 70 parts per billion (ppb) 8-hour average standard represents a reduction from the 2008 ozone standard of 75 ppb. States will be required to submit area designations in October 2016, with final designations promulgated by EPA in 2017. Attainment dates range from 2020 through 2037. EPA projects that 241 counties exceeded the 70 ppb standard in 2015 and that only 14 counties (excluding California) will exceed the standard in 2025 as a result of the full suite of EPA emission regulations that have been, or will be, implemented by that time.

With regard to the 2008 ozone NAAQS, EPA issued findings on June 30, 2015, that 24 states, including Illinois, Massachusetts and Pennsylvania, have failed to submit complete “good neighbor” SIPs to demonstrate how each state will address its air pollution impacts on downwind states. These findings establish a 2-year deadline for EPA to either approve a SIP or finalize a Federal Implementation Plain (FIP) that addresses the “good neighbor” requirement of the Clean Air Act. On September 29, 2015, U.S. EPA sent to the Office of Management and Budget a draft of its proposed Interstate Transport Rule update to address the 2008 ozone NAAQS. 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 SIP 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 that relate to requirements for states to include air quality monitoring and modeling in state implementation plans. Nonattainment county compliance with the one-hour SO2 standard is required by March 25, 2018. On August 10, 2015, EPA issued its final “Data Requirements Rule” that lays out EPA’s plan for designating currently undesignated areas that heretofore have not been designated due primarily to a lack of available monitoring data. Under this plan, all currently undesignated areas receiving a designation no later than 2020; included in the consent decree is a requirement that all large emission plants achieve emissions of less than 2,000 tons per year by 2017. 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.

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 SO2 and acid gases, and selective catalytic reduction technology for NOx.

As of September 30, 2015, Exelon had a $348 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 reflecting impairments recorded in 2013, 2014, and 2015, 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 allowed diesel backup generators to operate for up to 100 hours annually under certain emergency circumstances without meeting emissions limitations, but required 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, was not expected to result in additional megawatts of demand response to be bid into the PJM capacity auction. On

May 1, 2015, the D.C. Circuit Court reversed the 100 hour exemption contained in the 2013 RICE NESHAP final rule and remanded this issue back to EPA, leaving the remaining portions of the 2013 RICE NESHAP rule in effect. In a motion filed on July 15, 2015, EPA and respondent intervenors supporting EPA asked the D.C. Circuit Court to stay the Court's mandate with regard to the 100 hour exemption until May 1, 2016, or in the alternate, until at least August 31, 2015 on the claimed basis of the need to consider electric grid reliability and allow affected engines to install pollution control equipment if they intend to continue participation in demand response programs. On July 21, 2015, the D.C. Circuit Court responded to a separate motion with the clarification that the 100 hour exemption vacatur did not affect the 100 hour exemption with regard to units performing maintenance checks and readiness testing.

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. In the absence of Federal legislation, the U.S. EPA is 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 for new and existing units under Section 111 of the Clean Air Act. On August 3, 2015, the U.S. EPA finalized the Clean Power Plan rule for existing generation units. The rule was published in the Federal Register on October 23, 2015, and will become effective on December 22, 2015. The rule sets GHG emission reduction targets for each state, with reductions beginning in 2022, and the target achieved by 2030. States must submit an implementation plan to the U.S. EPA by September 2016, unless granted an extension of up to two years. States are granted latitude to select from a number of compliance options, which are designed to achieve the reductions in the most cost-effective manner. While the ultimate impact of the Clean Power Plan rule is expected to be favorable, Exelon and Generation cannot at this time predict to what extent the states' actions to comply with the Clean Power Plan's emission reduction targets will impact their future financial position, results of operations and cash flows.

Upon publication in the Federal Register a number of parties, including states, members of the electric industry and industry associations, filed suit in the U.S. Court of Appeals for the District of Columbia Circuit challenging the rule and seeking a stay of the rule pending the outcome of litigation.

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 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.

On June 30, 2015, NJDEP issued a draft NPDES permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system. The draft permit is subject to a public notice and comment period after which the NJDEP may make revisions before issuing the final permit expected during the first half of 2016.

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 became 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.

See Note 19 — 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 $350 million and $375 million of capital (which includes approximately $75 million for the CENG plants) and $50 million of operating expense (which includes approximately $5 million for the CENG plants). Generation has included in the capital estimate approximately $30 million for severe accident water addition and severe accident water management strategies at thirteen Mark I and II units (including two CENG units). On August 19, 2015, the NRC voted to stop pursuing the possibility of requiring drywell vents and standalone filters on vents. The severe accident water management strategies effectively eliminate the need for installation of drywell vents and standalone filters on vents. As Generation completes the design and installation planning for its actions, Generation will update these estimates. Generation's current assessments are specific to the Tier 1 recommendations as the NRC has not taken specific action with respect to the Tier 2 and Tier 3 recommendations. Exelon and Generation are unable to conclude at this time to what extent any actions to comply with the requirements of Tier 2 and Tier 3 will impact their future financial position, results of operations, and cash flows. Generation will continue to engage in nuclear industry assessments and actions and stakeholder input. See Item 1A. Risk Factors 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. The proposed legislation is pending and Exelon and Generation continue to work with stakeholders.

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. The proposed legislation is pending and ComEd continues to work with stakeholders.

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. On October 19, 2015, the ALJ issued its proposed order in ComEd's current distribution formula rate proceeding, recommending a total decrease to the revenue requirement of $68 million as compared to ComEd's requested decrease of $50 million. 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 requested an ROE of 10.95%. On September 10, 2015, PECO and interested parties filed with the PAPUC a petition for joint settlement for an increase of $127 million in annual distribution service revenue. No overall ROE was specified in the settlement. On October 28, 2015, the ALJ issued a Recommended Decision to the PAPUC that the joint settlement be approved. A final ruling from the PAPUC is expected by December 2015, and if approved, the new electric delivery rates will take effect on January 1, 2016.

Transmission Formula Rate Update Filing (Exelon, ComEd and BGE). On April 15, 2015 (and revised on May 19, 2015), ComEd filed its annual transmission formula rate update with the FERC, reflecting an increased revenue requirement of $86 million, including an increase of $68 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 took effect in June 2015, subject to review by the FERC and other parties, which is due by fourth quarter 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 took effect in June 2015, subject to review by 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 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 proposals filed by certain landowners to consider an alternate route for a three-mile segment of the transmission line. The rehearing order affirmed the route approved within the ICC's October 22, 2014 order. On July 8, 2015, the ICC approved ComEd's request for eminent domain to involuntarily acquire easements across 28 land parcels. On September 28, 2015, ComEd filed a petition with the ICC to acquire an additional eight parcels through eminent domain. ComEd began construction of the line during the second quarter of 2015 with an in-service date expected in the second quarter of 2017.

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. On July 20, 2015, FERC approved a settlement between Ameren and its customers to resolve the matter. ComEd believes that the FERC settlement 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. On October 25, 2012, 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 that, among other things, rejected the arguments of the PJM Transmission Owners that changes to the PJM governing documents were entitled to review under the *Mobile-Sierra* standard. The FERC's March 22, 2013 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, PECO 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. On May 15, 2014, FERC denied the PJM Transmission Owner rehearing request. Several parties filed an appeal of the FERC's May 15, 2014, Order upholding PJM's right of first refusal language in the D.C. Circuit. The ultimate outcome of this proceeding cannot be predicted at this time, however, could be material to Exelon, ComEd, PECO and BGE's results of operations and cash flows.

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 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 ROE 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 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. On September 14, 2015, the complainants and respondents filed a joint motion to suspend the hearing schedule because they have reached a settlement in principle to resolve the ROE issue. On September 15, 2015, the Chief Administrative Law Judge issued an order granting the motion, and setting October 15, 2015 as the date for the moving parties to either file a settlement or file a status report detailing the timetable for filing a settlement, which was subsequently extended to October 30, 2015. On October 30, 2015, the parties filed a status report stating their intent to either file a settlement or file another status report during the fourth quarter of 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. BGE has established a reserve, which management believes is adequate for what it considers to be the most likely outcome. The estimated annual ongoing reduction in revenues if FERC approved the ROEs as originally requested by the parties in their initial filings is approximately $11 million. If FERC were to order a reduction of BGE's base ROE to 8.7% and 8.8% as sought in the first and second complaints, respectively (while retaining the 50 basis points of any incentives that were credited to the base ROE for certain new transmission investment), the result would be a refund to customers of approximately $13 million and $14 million for the first and second fifteen month refund windows, respectively, for a total refund to customers of $27 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 to be effective January 1, 2015 including a true-up of costs estimates included in the 2014 surcharge, along with its 2015 project list and projected capital estimates of $78 million to be included in the 2015 surcharge calculation. At its December 17, 2014 weekly Administrative Meeting, the MDPSC approved BGE's 2015 project list and the proposed surcharge for 2015, which included the true-up of the 2014 surcharge. As of September 30, 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. During the third quarter of 2015, the residential consumer advocate, MDPSC, and BGE filed briefs. The Court of Special Appeals has set oral argument in this matter for November 3, 2015. BGE cannot predict the outcome of this appeal. However, if the consumer advocates appeal is successful, BGE could seek recovery of infrastructure replacement costs through other regulatory mechanisms. 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.

Employees

During 2015, Generation successfully ratified the collective bargaining agreement (CBA) between the IBEW and Clinton Power Station through 2021, the CBA with that Security Officer union at Braidwood, Byron and Three Mile Island through 2018, 2019, and 2021, respectively. In addition, two union contracts at Mystic 7 and Mystic 8/9 were successfully negotiated and ratified through 2021.

Negotiations for a first contract of the ComEd Distribution Testing Technicians (DT), a group of 49 technicians represented by IBEW Local 15, was successfully ratified. After a two-year transition period ending December 31, 2017, the DT group will cease to exist and most of the existing duties will be absorbed by existing represented work group positions within the current ComEd IBEW Local 15 CBA, which will expire on September 30, 2019.

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 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 September 30, 2015, the Registrants' critical accounting policies and estimates had not changed significantly from December 31, 2014.

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Results of Operations

Net Income Attributable to Common Shareholders by Registrant

	Three Months Ended September 30, 2015[a]	Three Months Ended September 30, 2014	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2015[a]	Nine Months Ended September 30, 2014	Favorable (Unfavorable) Variance
Exelon	$ 629	$ 993	$ (364)	$ 1,959	$ 1,604	$ 355
Generation	377	771	(394)	1,218	926	292
ComEd	149	126	23	339	335	4
PECO	90	81	9	299	255	44
BGE	51	46	5	202	146	56

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

Results of Operations — Generation

	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014 [a]	Favorable (Unfavorable) Variance
Operating revenues	$ 4,768	$ 4,412	$ 356	$14,841	$12,591	$ 2,250
Purchased power and fuel expense	2,519	1,880	(639)	7,800	7,071	(729)
Revenue net of purchased power and fuel[b]	2,249	2,532	(283)	7,041	5,520	1,521
Other operating expenses						
Operating and maintenance	1,241	1,266	25	3,860	3,765	(95)
Depreciation and amortization	264	253	(11)	774	719	(55)
Taxes other than income	123	127	4	369	350	(19)
Total other operating expenses	1,628	1,646	18	5,003	4,834	(169)
Equity in earnings (losses) of unconsolidated affiliates	—	1	(1)	—	(20)	20
Gain on sales of assets	1	338	(337)	7	355	(348)
Gain on consolidation and acquisition of businesses	—	—	—	—	261	(261)
Operating income	622	1,225	(603)	2,045	1,282	763
Other income and (deductions)						
Interest expense	(68)	(89)	21	(269)	(261)	(8)
Other, net	(257)	4	(261)	(193)	306	(499)
Total other income and (deductions)	(325)	(85)	(240)	(462)	45	(507)
Income before income taxes	297	1,140	(843)	1,583	1,327	256
Income taxes (benefit)	(36)	291	327	371	290	(81)
Equity in losses of unconsolidated affiliates	(1)	—	(1)	(4)	—	(4)
Net income	332	849	(517)	1,208	1,037	171
Net income (loss) attributable to noncontrolling interests	(45)	78	123	(10)	111	121
Net income attributable to membership interest	$ 377	$ 771	$ (394)	$ 1,218	$ 926	$ 292

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning on April 1, 2014, the 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 Attributable to Membership Interest

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. Generation's net income attributable to membership interest for the three months ended September 30, 2015 decreased compared to the same period in 2014 primarily due to lower revenue net of purchased power and fuel expense, lower gains on sales of assets and decreased other income, partially offset by decreased operating and maintenance and income tax expense. The decrease in revenue net of purchased power and fuel expense relates to mark-to-market losses in 2015 compared to mark-to-market gains in 2014 and lower margins and capacity revenues resulting from the absence of generating units sold in 2014, partially offset by the benefit of lower cost to serve load, the inclusion of Integrys' results in 2015, and increased load served. The decrease in gains on sales of assets is primarily due to the absence in 2015 of the gain on sale of Safe Harbor Water Power Corporation recorded in 2014. The decrease in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. The decrease in operating and maintenance expense is primarily related to a reduction in merger and integration costs in 2015 and the absence of impairment charges for certain generating assets held for sale recorded in 2014, partially offset by increased contracting costs primarily due to growth development projects at Generation. The decrease in income taxes is primarily due to the absence of the gain on the sale of Safe Harbor Water Power Corporation recorded in 2014 and an increase in the domestic production activities deduction.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. Generation's net income attributable to membership interest for the nine months ended September 30, 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, decreased gains on sales of assets, the 2014 gain recognized as a result of the consolidation of CENG, decreased other income and increased income taxes. The increase in revenue net of purchased power and fuel expense relates to the inclusion of CENG's results on a fully consolidated basis in 2015, a reduction in the number of nuclear outage days in 2015, the inclusion of Integrys' results in 2015, the benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), the cancellation of the DOE spent nuclear fuel disposal fee, increased capacity prices, favorability from portfolio management optimization activities, increased load served and mark-to-market gains in 2015 compared to mark-to-market losses in 2014, partially offset by lower margins and capacity revenues resulting from the 2014 sales of generating assets, lower realized energy prices and the absence of fuel optimization opportunities realized in 2014 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, partially offset by the absence of impairment charges for wind generating assets and certain assets held for sale recorded in 2014. The decrease in gains on sales of assets is primarily due to the absence in 2015 of the gain on sale of Safe Harbor Water Power Corporation in 2014. The decrease in other income is primarily due to the change in realized and unrealized gains and losses on NDT funds. 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, partially offset by the gain on the consolidation of CENG in 2014 and an increase in the domestic production activities deduction.

Revenue Net of Purchased Power and Fuel Expense

The basis for Generation's reportable segments is the integrated management of its electricity business that is located in different geographic regions, and largely representative of the footprints of ISO/RTO and/or NERC regions, which utilize multiple supply sources to provide electricity through various distribution channels (wholesale and retail). Generation's hedging strategies and risk metrics are also aligned with these same geographic regions. Descriptions of each of Generation's six reportable segments are as follows:

- Mid-Atlantic represents operations in the eastern half of PJM, which includes New Jersey, Maryland, Virginia, West Virginia, Delaware, the District of Columbia and parts of Pennsylvania and North Carolina.
- Midwest represents operations in the western half of PJM, which includes portions of Illinois, Pennsylvania, 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:
  - South represents operations in the FRCC, MISO's Southern Region, and the remaining portions of the SERC not included within MISO or PJM, which includes all or most of Florida, Arkansas, Louisiana, Mississippi, Alabama, Georgia, Tennessee, North Carolina, South Carolina and parts of Missouri, Kentucky and Texas. Generation's South region also includes operations in the SPP, covering Kansas, Oklahoma, most of Nebraska and parts of New Mexico, Texas, Louisiana, Missouri, Mississippi and Arkansas.
  - West represents operations in the WECC, which includes California ISO, and covers the states of California, Oregon, Washington, Arizona, Nevada, Utah, Idaho, Colorado, and parts of New Mexico, Wyoming and South Dakota.
  - Canada represents operations across the entire country of Canada and includes AESO, OIESO and the Canadian portion of MISO.

The following business activities are not allocated to a region, and are reported in the table below in Other: natural gas, as well as other miscellaneous business activities that are not significant to Generation's overall operating revenues or results of operations. Further, the following activities are not allocated to a region, and are reported in the table below 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.

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For the three and nine months ended September 30, 2015 and 2014, Generation's revenue net of purchased power and fuel expense by region were as follows:

	Three Months Ended September 30,			
	2015	2014	Variance	% Change
Mid-Atlantic[b]	$ 991	$ 935	$ 56	6.0%
Midwest[c]	752	716	36	5.0%
New England	133	90	43	47.8%
New York	167	186	(19)	(10.2)%
ERCOT	111	109	2	1.8%
Other Power Regions[d]	83	68	15	22.1%
Total electric revenue net of purchased power and fuel expense	2,237	2,104	133	6.3%
Proprietary trading	—	23	(23)	(100.0)%
Mark-to-market gains (losses)	(139)	267	(406)	(152.1)%
Other[e]	151	138	13	9.4%
Total revenue net of purchased power and fuel expense	$ 2,249	$ 2,532	$ (283)	(11.2)%

	Nine Months Ended September 30,			
	2015	2014	Variance	% Change
Mid-Atlantic[a][b][f]	$ 2,663	$ 2,550	$ 113	4.4%
Midwest[c]	2,195	1,877	318	16.9%
New England	379	290	89	30.7%
New York[a][f]	498	313	185	59.1%
ERCOT	235	250	(15)	(6.0)%
Other Power Regions[d]	193	249	(56)	(22.5)%
Total electric revenue net of purchased power and fuel expense	6,163	5,529	634	11.5%
Proprietary trading	3	43	(40)	(93.0)%
Mark-to-market gains (losses)	258	(477)	735	154.1%
Other[e]	617	425	192	45.2%
Total revenue net of purchased power and fuel expense	$ 7,041	$ 5,520	$ 1,521	27.6%

(a) On April 1, 2014, Generation assumed operational control of CENG's nuclear fleet. As a result, beginning April 1, 2014, the financial results include CENG's results 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 includes South, West and Canada.
(e) Other represents activities not allocated to a region. See text above for a description of included activities. Also includes a $4 million decrease to RNF and a $20 million increase to RNF for the amortization of intangible assets related to commodity contracts for the three and nine months ended September 30, 2015, respectively, and $15 million increase to RNF and $78 million decrease to RNF for the amortization of intangible assets related to commodity contracts for the three and nine months ended September 30, 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 nine months ended September 30, 2014.

Generation's supply sources by region are summarized below:

Supply Source (GWh)	Three Months Ended September 30, 2015	2014	Variance	% Change
Nuclear Generation				
Mid-Atlantic[a]	16,446	15,993	453	2.8%
Midwest	23,927	24,379	(452)	(1.9)%
New York[a]	4,807	4,891	(84)	(1.7)%
Total Nuclear Generation	45,180	45,263	(83)	(0.2)%
Fossil and Renewables[a]				
Mid-Atlantic	719	2,385	(1,666)	(69.9)%
Midwest	262	212	50	23.6%
New England	1,840	1,789	51	2.9%
New York	1	1	—	—%
ERCOT	2,306	2,331	(25)	(1.1)%
Other Power Regions[c]	1,945	2,285	(340)	(14.9)%
Total Fossil and Renewables	7,073	9,003	(1,930)	(21.4)%
Purchased Power				
Mid-Atlantic	3,511	1,110	2,401	n.m.
Midwest	515	260	255	98.1%
New England	5,787	3,231	2,556	79.1%
ERCOT	2,422	2,184	238	10.9%
Other Power Regions[c]	5,189	4,397	792	18.0%
Total Purchased Power	17,424	11,182	6,242	55.8%
Total Supply/Sales by Region[d]				
Mid-Atlantic[e]	20,676	19,488	1,188	6.1%
Midwest[e]	24,704	24,851	(147)	(0.6)%
New England	7,627	5,020	2,607	51.9%
New York	4,808	4,892	(84)	(1.7)%
ERCOT	4,728	4,515	213	4.7%
Other Power Regions[c]	7,134	6,682	452	6.8%
Total Supply/Sales by Region	69,677	65,448	4,229	6.5%

Supply Source (GWh)	Nine Months Ended September 30, 2015	2014	Variance	% Change
Nuclear Generation				
Mid-Atlantic[(a)]	47,783	43,042	4,741	11.0%
Midwest	69,802	70,223	(421)	(0.6)%
New York[(a)]	14,057	8,657	5,400	62.4%
Total Nuclear Generation	131,642	121,922	9,720	8.0%
Fossil and Renewables[(a)]				
Mid-Atlantic	2,028	8,758	(6,730)	(76.8)%
Midwest	1,057	948	109	11.5%
New England	2,575	4,822	(2,247)	(46.6)%
New York	3	3	—	—%
ERCOT	4,600	5,541	(941)	(17.0)%
Other Power Regions[(c)]	6,014	5,954	60	1.0%
Total Fossil and Renewables	16,277	26,026	(9,749)	(37.5)%
Purchased Power				
Mid-Atlantic[(b)]	6,719	5,152	1,567	30.4%
Midwest	1,511	1,491	20	1.3%
New England	17,937	7,591	10,346	136.3%
New York[(b)]	—	2,857	(2,857)	(100.0)%
ERCOT	7,569	6,685	884	13.2%
Other Power Regions[(c)]	12,666	11,406	1,260	11.0%
Total Purchased Power	46,402	35,182	11,220	31.9%
Total Supply/Sales by Region[(d)]				
Mid-Atlantic[(e)]	56,530	56,952	(422)	(0.7)%
Midwest[(e)]	72,370	72,662	(292)	(0.4)%
New England	20,512	12,413	8,099	65.2%
New York	14,060	11,517	2,543	22.1%
ERCOT	12,169	12,226	(57)	(0.5)%
Other Power Regions[(c)]	18,680	17,360	1,320	7.6%
Total Supply/Sales by Region	194,321	183,130	11,191	6.1%

(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 and nine months ended September 30, 2015 includes physical volumes of 3,808 GWh and 10,835 GWh in the Mid-Atlantic region and 4,807 GWh and 14,057 GWh in the New York region for CENG. Nuclear generation for the three and nine months ended September 30, 2014 includes physical volumes of 3,726 GWh and 7,507 GWh in the Mid-Atlantic region and 4,891 GWh and 8,657 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 nine months ended September 30, 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 includes South, West and Canada.

(d) Excludes physical proprietary trading volumes of 1,913 GWh and 3,006 GWh for the three months ended September 30, 2015 and 2014, respectively, and 5,378 GWh and 8,129 GWh for nine months ended September 30, 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

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $56 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the benefit of lower cost to serve load, increased load volumes served, higher nuclear volumes, and higher capacity revenues, partially offset by lower generation volumes due to the sale of various generating assets.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $113 million increase in revenue net of purchased power and fuel expense in the Mid-Atlantic was primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015, benefit of lower cost to serve load (which includes the absence of higher procurement costs for replacement power due to extreme cold weather in the first quarter of 2014), increased load volumes served, higher nuclear volumes, the cancellation of the DOE spent nuclear fuel disposal fee, and favorability from portfolio management optimization activities, partially offset by lower capacity revenues, and lower generation volumes due to the sale of generating assets.

Midwest

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $36 million increase in revenue net of purchased power and fuel expense in the Midwest was primarily due to the benefit of lower cost to serve load, increased load volumes served, the inclusion of Integrys' results in 2015, and higher capacity revenues, partially offset by lower nuclear volumes.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $318 million increase in revenue net of purchased power and fuel expense in the Midwest was primarily due to higher capacity revenues, the benefit of lower cost to serve load, increased load volumes served, the inclusion of Integrys' results in 2015, the cancellation of the DOE spent nuclear fuel disposal fee, and favorability from portfolio management optimization activities, partially offset by lower nuclear volumes.

New England

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $43 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, increased load volumes served, and the inclusion of Integrys' results in 2015, partially offset by lower generation volumes due to the sale of a generating asset.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $89 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, increased load volumes served and the inclusion of Integrys' results in 2015, partially offset by lower generation volumes due to the sale of a generating asset.

New York

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $19 million decrease in revenue net of purchased power and fuel expense in New York was primarily due to lower capacity revenues, lower realized energy prices, and lower nuclear volumes.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $185 million increase in revenue net of purchased power and fuel expense in New York was primarily due to the inclusion of CENG's results on a fully consolidated basis in 2015 and higher nuclear volumes, partially offset by lower realized energy prices and lower capacity revenues.

ERCOT

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $2 million increase in revenue net of purchased power and fuel expense in ERCOT was primarily due to lower fuel costs, partially offset by lower realized energy prices.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $15 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 a generating asset, partially offset by the absence of higher procurement costs for replacement power in 2014 and lower fuel costs.

Other Power Regions

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $15 million increase in revenue net of purchased power and fuel expense in Other Power Regions was primarily due to higher generation volumes from power purchase agreements and lower fuel costs, partially offset by lower realized energy prices.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $56 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, partially offset by higher generation volumes from power purchase agreements and lower fuel costs.

Proprietary trading

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The $23 million decrease in revenue net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of gains on congestion trading products.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $40 million decrease in revenue net of purchased power and fuel expense in Proprietary trading was primarily due to the absence of gains on congestion trading products.

Mark-to-market

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 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 losses on economic hedging activities were $139 million for the three months ended September 30, 2015 compared to gains of $267 million for the three months ended September 30, 2014. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — Derivative Financial Instruments of the Combined Notes to the Consolidated Financial Statements for information on gains and losses associated with mark-to-market derivatives.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 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 $258 million for the nine months ended September 30, 2015 compared to losses of $477 million for the nine months ended September 30, 2014. See Notes 9 — Fair Value of Financial Assets and Liabilities and 10 — 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 September 30, 2015 Compared to Three Months Ended September 30, 2014. The $13 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.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The $192 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.

Nuclear Fleet Capacity Factor and Production Costs

The following table presents nuclear fleet operating data for the three and nine months ended September 30, 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 fees, 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Nuclear fleet capacity factor[(a)]	95.5%	96.5%	93.8%	94.1%
Nuclear fleet production cost per MWh[(a)]	$18.26	$17.99	$19.44	$19.58

(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, beginning on April 1, 2014, the financial results include CENG's results of operations on a fully consolidated basis.

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of refueling outages days during the three months ended September 30, 2015 compared to the same period in 2014, partially offset by a lower number of non-refueling outage days. For the three months ended September 30, 2015 and 2014, refueling outage days totaled 27 and 18, respectively. During the same periods, non-refueling outage days totaled 11 and 20, respectively. Production costs per MWh were higher for the three months ended September 30, 2015 as compared to the same period in 2014 due to a lower fleet capacity factor.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The nuclear fleet capacity factor, which excludes Salem, decreased primarily due to a higher number of refueling outage days and non-outage energy losses during the nine months ended September 30, 2015 compared to the same period in 2014, partially offset by a lower number of unplanned outage days. For the nine months ended September 30, 2015 and 2014, refueling outage days totaled 187 (of which 51 were related to CENG plants) and 178 (of which 52 were related to CENG plants), respectively. During the same periods, non-refueling outage days totaled 61 (of which 12 were related to CENG) and 84 (of which 5 were related to CENG), respectively. Production costs per MWh were lower for the nine months ended September 30, 2015 as compared to the same period in 2014, due to the elimination of the spent nuclear fuel disposal fee in 2014, partially offset by the inclusion of CENG.

Operating and Maintenance

The changes in operating and maintenance expense for the three and nine months ended September 30, 2015 compared to the same periods in 2014, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)[(a)]
Labor, other benefits, contracting, materials	$ 45	$ 202
Corporate allocations [(b)]	6	17
Materials and supplies related expenses	10	10
Asset retirement obligation update [(c)]	8	8
Pension and non-pension postretirement benefits expense	6	10
Nuclear refueling outage costs, including the co-owned Salem plants	2	8
Regulatory fees and assessment	2	12
Midwest Generation bankruptcy recoveries	—	(14)
Accretion expense [(d)]	(2)	21
Merger and integration costs	(46)	(56)
Impairment of long-lived assets [(e)]	(47)	(135)
Other	(9)	12
Increase (decrease) in operating and maintenance expense	$ (25)	$ 95

(a) On April 1, 2014, Generation assumed operational control of CENG’s nuclear fleet. As a result, beginning on April 1, 2014, the financial results include CENG’s results of operations on a fully consolidated basis.
(b) Reflects an increased share of corporate allocated costs.
(c) Reflects the impact of the annual update of Generation’s nuclear decommissioning obligation for Non-Regulatory Agreement Units.
(d) Includes the elimination of activity for the Regulatory Agreement Units, including the elimination of revenue and depreciation 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.
(e) Reflects the impact of a 2014 charge to earnings related to the impairment of wind generating assets and certain generation assets held for sale.

Depreciation and Amortization

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. Depreciation and amortization expense for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 remained relatively consistent.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The increase in depreciation and amortization expense for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 is primarily due the inclusion of CENG’s results on a fully consolidated basis in 2015.

Taxes Other Than Income

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. Taxes other than income taxes, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. Taxes other than income for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 remained relatively level.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. Taxes other than income taxes, which can vary period to period, include non-income municipal and state utility taxes, real estate taxes and payroll taxes. The increase in taxes other than income for the nine months ended September 30, 2015 compared to the nine months ended September 30, 2014 is primarily due the inclusion of CENG’s results on a fully consolidated basis in 2015.

Equity in Losses of Unconsolidated Affiliates

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. Equity in losses of unconsolidated affiliates for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 remained relatively consistent.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The decrease in equity in losses of unconsolidated affiliates for the nine months ended September 30, 2015 compared to the nine months ended September 30, 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 losses in 2015.

Gain on Sales of Assets

The unfavorable change in gain on sales of assets for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 2014 is primarily due to the gain on sale of Safe Harbor Water Power Corporation, which was recorded in 2014.

Interest Expense

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. The decrease in interest expense for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 is primarily related to the favorable settlement in 2015 of an income tax position on Constellation's pre-acquisition tax returns, partially offset by increased interest expense due to higher outstanding debt.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. The increase in interest expense for the three months ended September 30, 2015 compared to the three months ended September 30, 2014 is primarily related to higher outstanding debt, partially offset by the favorable settlement in 2015 of an income tax position on Constellation's pre-acquisition tax returns.

Other, Net

The decrease in Other, net for the three and nine months ended September 30, 2015 compared to the three and nine months ended September 30, 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 $(55) million and $(16) million for the three months ended September 30, 2015 and 2014, respectively, and $(44) million and $50 million for the nine months ended September 30, 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 13 — Nuclear Decommissioning for additional information regarding NDT funds. For the three and nine months ended September 30, 2015, the change in Other, net also included a benefit recorded in 2014 for the favorable settlement of certain income tax positions on Constellation's pre-acquisition tax returns.

The following table provides unrealized and realized gains (losses) on the NDT funds of the Non-Regulatory Agreement Units recognized in Other, net for the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015[(a)]	2014
Net unrealized gains (losses) on decommissioning trust funds	$ (218)	$ (41)	$ (274)	$ 100
Net realized gains (losses) on sale of decommissioning trust funds	(3)	17	53	42

(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.

Effective Income Tax Rate

The effective income tax rate was (12.1)% and 23.4% for the three and nine months ended September 30, 2015, respectively, compared to 25.5% and 21.9% for the same periods during 2014. See Note 12 — 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 September 30, 2015	Three Months Ended September 30, 2014	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	Favorable (Unfavorable) Variance
Operating revenue	$ 1,376	$ 1,222	$ 154	$ 3,709	$ 3,484	$ 225
Purchased power expense	390	326	(64)	991	915	(76)
Revenue net of purchased power expense[(a)(b)]	986	896	90	2,718	2,569	149
Other operating expenses						
Operating and maintenance	404	359	(45)	1,166	1,040	(126)
Depreciation and amortization	176	174	(2)	528	521	(7)
Taxes other than income	79	76	(3)	225	225	—
Total other operating expenses	659	609	(50)	1,919	1,786	(133)
Operating income	327	287	40	799	783	16
Other income and (deductions)						
Interest expense, net	(83)	(81)	(2)	(248)	(241)	(7)
Other, net	4	4	—	14	14	—
Total other income and (deductions)	(79)	(77)	(2)	(234)	(227)	(7)
Income before income taxes	248	210	38	565	556	9
Income taxes	99	84	(15)	226	221	(5)
Net income	$ 149	$ 126	$ 23	$ 339	$ 335	$ 4

(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.

(b) For regulatory recovery mechanisms, including ComEd's distribution and transmission formula rates, and riders, revenues increase and decrease i) as fully recoverable costs fluctuate (with no impact on net earnings), and ii) pursuant to changes in rate base, capital structure and ROE (which impact net earnings).

Net Income

Three Months Ended September 30, 2015 Compared to Three Months Ended September 30, 2014. ComEd's net income for the three months ended September 30, 2015 was higher than the same period in 2014, primarily due to favorable weather and increased electric distribution and transmission formula rate revenues (reflecting the impacts of increased capital investment, partially offset by lower allowed electric distribution ROE).

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. ComEd's net income for the nine months ended September 30, 2015 was higher than the same period in 2014, primarily due to increased electric distribution and transmission formula rate revenues (reflecting the impacts of increased capital investment, partially offset by lower allowed ROE).

Operating Revenue Net of Purchased Power Expense

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 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.

Retail deliveries purchased from competitive electric generation suppliers (as a percentage of kWh sales) for the three and nine months ended September 30, 2015, compared to the same period in 2014, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Electric	75%	79%	77%	80%

Retail customers purchasing electric generation from competitive electric generation suppliers at September 30, 2015 and 2014 consisted of the following:

	September 30, 2015		September 30, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	1,664,600	43%	2,422,900	63%

The City of Chicago previously participated in ComEd's customer choice program and purchased electricity from Constellation (formerly Integrys). As of September 2015, the City of Chicago no longer participates in the customer choice program and began purchasing its electricity from ComEd. It is anticipated that by the end of the fourth quarter 2015 approximately 43% of retail customers and 72% 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 has increased as a result of the City of Chicago switching, but is fully offset in Purchased power expense.

The changes in ComEd's Revenue net of purchased power expense for the three and nine months ended September 30, 2015, compared to the same periods in 2014 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Weather	$ 17	$ (2)
Volume	(1)	(14)
Electric distribution revenue	36	80
Transmission revenue	11	24
Regulatory required programs	21	2
Uncollectible accounts recovery, net	(6)	37
Pricing and customer mix	12	13
Revenue subject to refund	—	9
Increase in revenue net of purchased power expense	$ 90	$ 149

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 September 30, 2015, favorable weather conditions increased Operating revenue net of purchased power expense when compared to the same period in 2014.

For the nine months ended September 30, 2015, unfavorable weather conditions reduced Operating revenue net of purchased power expense when compared to the same period in 2014.

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 and nine months ended September 30, 2015, and 2014, consisted of the following:

Heating and Cooling Degree-Days				% Change	
Three Months Ended September 30,	**2015**	**2014**	**Normal**	**From 2014**	**From Normal**
Heating Degree-Days	55	111	119	(50.5)%	(53.8)%
Cooling Degree-Days	634	537	613	18.1%	3.4%
Nine Months Ended September 30,					
Heating Degree-Days	4,373	4,680	4,048	(6.6)%	8.0%
Cooling Degree-Days	805	796	831	1.1%	(3.1)%

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 and nine months periods 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, electric distribution revenue varies from year to year based on fluctuations in the underlying costs, investments being recovered, allowed ROE, and other billing determinants. ComEd’s allowed ROE 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 and nine months ended September 30, 2015, ComEd recorded increased electric distribution revenue primarily due to increased capital investment, partially offset by lower allowed ROE 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 and nine months ended September 30, 2015, ComEd recorded increased transmission revenue primarily 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 and nine months ended September 30, 2015, as compared to the same periods in 2014.

Revenue Subject to Refund. ComEd records revenue subject to refund based upon its best estimate of customer collections that may be required to be refunded. Revenue net of purchase power was higher for the nine months ended September 30, 2015 due to the one-time revenue refund associated with Rider AMP recorded in the second quarter of 2014. See Note 3—Regulatory Matters of the Exelon 2014 Form 10-K for additional information regarding Rider AMP.

Operating and Maintenance Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2015	2014	Increase	2015	2014	Increase
Operating and maintenance expense — baseline	$ 338	$ 314	$ 24	$ 1,005	$ 881	$ 124
Operating and maintenance expense — regulatory required programs[(a)]	66	45	21	161	159	2
Total operating and maintenance expense	$ 404	$ 359	$ 45	$ 1,166	$ 1,040	$ 126

(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 and nine months ended September 30, 2015 compared to the same periods in 2014, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase
Baseline		
Labor, other benefits, contracting and materials[(a)]	$ 2	$ 38
Pension and non-pension postretirement benefits expense	9	8
Storm-related costs	6	12
Uncollectible accounts expense — provision[(b)]	(2)	3
Uncollectible accounts expense — recovery, net[(b)]	(4)	34
Other[(c)]	13	29
	24	124
Regulatory required programs		
Energy efficiency and demand response programs	21	2
	21	2
Increase in operating and maintenance expense	$ 45	$ 126

(a) Primarily reflects increased contracting costs related to preventative maintenance and other projects for the three and nine months ended September 30, 2015.

(b) 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 and nine months ended September 30, 2015, ComEd recorded a net reduction and increase, respectively, in operating and maintenance expense related to uncollectible accounts due to the timing of regulatory cost recovery. An equal and offsetting amount has been recognized in operating revenue for the periods presented.

(c) Primarily reflects increased IT support services costs from BSC.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2015, compared to the same period in 2014, remained relatively consistent.

Depreciation and amortization expense increased for the nine months ended September 30, 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 and nine months ended September 30, 2015, compared to the same periods in 2014.

Interest Expense, Net

The changes in interest expense, net for the three and nine months ended September 30, 2015, compared to the same periods in 2014, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Interest expense related to uncertain tax positions	$ 1	$ —
Interest expense on debt (including financing trusts)[(a)]	3	9
Other	(2)	(2)
Increase in interest expense, net	$ 2	$ 7

(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 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information on ComEd's debt obligations.

Effective Income Tax Rate

ComEd's effective income tax rate was 39.9% and 40.0% for the three months ended September 30, 2015 and 2014, respectively. ComEd's effective income tax rate was 40.0% and 39.7% for the nine months ended September 30, 2015 and 2014, respectively. See Note 12 — 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

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2015	2014	% Change	Weather-Normal % Change	Nine Months Ended September 30, 2015	2014	% Change	Weather-Normal % Change
Retail Deliveries[a]								
Residential	7,919	7,332	8.0%	(0.6)%	20,602	20,920	(1.5)%	(1.8)%
Small commercial & industrial	8,579	8,366	2.5%	0.3%	24,305	24,456	(0.6)%	(0.4)%
Large commercial & industrial	7,250	7,245	0.1%	(1.3)%	20,807	21,109	(1.4)%	(1.3)%
Public authorities & electric railroads	295	301	(2.0)%	(2.1)%	964	1,001	(3.7)%	(3.1)%
Total retail deliveries	24,043	23,244	3.4%	(0.5)%	66,678	67,486	(1.2)%	(1.2)%

Number of Electric Customers	As of September 30, 2015	2014
Residential	3,524,253	3,486,438
Small commercial & industrial	369,151	367,446
Large commercial & industrial	1,996	1,992
Public authorities & electric railroads	4,826	4,821
Total	3,900,226	3,860,697

Electric Revenue	Three Months Ended September 30, 2015	2014	% Change	Nine Months Ended September 30, 2015	2014	% Change
Retail Sales[a]						
Residential	$ 690	$ 566	21.9%	$ 1,785	$ 1,572	13.5%
Small commercial & industrial	361	349	3.4%	1,029	1,033	(0.4)%
Large commercial & industrial	121	115	5.2%	339	343	(1.2)%
Public authorities & electric railroads	10	10	—%	33	35	(5.7)%
Total retail	1,182	1,040	13.7%	3,186	2,983	6.8%
Other revenue[b]	194	182	6.6%	523	501	4.4%
Total electric revenue	$ 1,376	$ 1,222	12.6%	$ 3,709	$ 3,484	6.5%

(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 September 30, 2015	Three Months Ended September 30, 2014	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	Favorable (Unfavorable) Variance
Operating revenue	$ 740	$ 693	$ 47	$ 2,386	$ 2,343	$ 43
Purchased power and fuel	278	255	(23)	953	960	7
Revenue net of purchased power and fuel expense[(a)]	462	438	24	1,433	1,383	50
Other operating expenses						
Operating and maintenance	196	204	8	609	668	59
Depreciation and amortization	68	59	(9)	198	176	(22)
Taxes other than income	44	42	(2)	125	122	(3)
Total other operating expenses	308	305	(3)	932	966	34
Gain on sale of assets	—	—	—	1	—	1
Operating income	154	133	21	502	417	85
Other income and (deductions)						
Interest expense, net	(28)	(29)	1	(84)	(85)	1
Other, net	1	2	(1)	3	5	(2)
Total other income and (deductions)	(27)	(27)	—	(81)	(80)	(1)
Income before income taxes	127	106	21	421	337	84
Income taxes	37	25	(12)	122	82	(40)
Net income attributable to common shareholder	$ 90	$ 81	$ 9	$ 299	$ 255	$ 44

(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 September 30, 2015 Compared to Three Months Ended September 30, 2014. PECO's net income attributable to common shareholder for the three months ended September 30, 2015 was higher than the same period in 2014, primarily due to favorable weather.

Nine Months Ended September 30, 2015 Compared to Nine Months Ended September 30, 2014. PECO's net income attributable to common shareholder for the nine months ended September 30, 2015 was higher than the same period in 2014, primarily due to favorable weather and a decrease in operating and maintenance expense due to a decrease in storm costs.

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 as specified in the PAPUC-approved tariffs that are designed to recover or refund the difference between the actual cost of electric supply and natural gas and the amount included in rates in accordance with

PECO'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.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2015 and 2014, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Electric	69%	70%	69%	70%
Natural Gas	31%	27%	24%	22%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2015 and 2014 consisted of the following:

	September 30, 2015		September 30, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	558,300	35%	537,000	34%
Natural Gas	81,100	16%	76,200	15%

The changes in PECO's operating revenue net of purchased power and fuel expense for the three and nine months ended September 30, 2015 compared to the same period in 2014 consisted of the following:

	Three Months Ended September 30, Increase (Decrease)			Nine Months Ended September 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Weather	$ 32	$—	$ 32	$ 52	$ 1	$ 53
Volume	(1)	—	(1)	3	5	8
Pricing	(7)	—	(7)	(8)	2	(6)
Regulatory required programs	1	—	1	4	—	4
Other	(1)	—	(1)	(10)	1	(9)
Total increase	$ 24	$—	$ 24	$ 41	$ 9	$ 50

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 and nine months ended September 30, 2015 compared to the same periods in 2014, operating revenue net of purchased power and fuel expense was higher primarily due to the impact of favorable weather conditions in PECO's service territory.

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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 PECO's service territory. The changes in heating and cooling degree days in PECO's service territory for the three and nine months ended September 30, 2015 compared to the same period in 2014 and normal weather consisted of the following:

Heating and Cooling Degree-Days	2015	2014	Normal	% Change From 2014	% Change From Normal
Three Months Ended September 30,					
Heating Degree-Days	—	14	38	(100.0)%	(100.0)%
Cooling Degree-Days	1,186	911	929	30.2%	27.7%
Nine Months Ended September 30,					
Heating Degree-Days	3,264	3,251	2,981	0.4%	9.5%
Cooling Degree-Days	1,699	1,286	1,278	32.1%	32.9%

Volume. The increase in gas operating revenue net of fuel expense related to delivery volume, exclusive of the effects of weather, for the nine months ended September 30, 2015 compared to the same period in 2014, primarily reflects the impact of moderate economic and customer growth partially offset by energy efficiency initiatives on customer usages.

The increase in electric operating revenue net of purchased power expense related to delivery volume for the nine months ended September 30, 2015, is primarily related to the shift in the volume profile across classes from lower priced classes to higher priced classes.

Pricing. The decrease in electric operating revenues net of purchased power and fuel expense for the three and nine months ended September 30, 2015 compared to the same periods in 2014 is primarily attributable to lower overall effective rates due to increased usage across all major customer classes.

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 and nine months ended September 30, 2015 compared to the same periods 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 September 30, 2015	Three Months Ended September 30, 2014	Increase (Decrease)	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	Increase (Decrease)
Operating and maintenance expense — baseline	$ 170	$ 178	$ (8)	$ 528	$ 592	$ (64)
Operating and maintenance expense — regulatory required programs[(a)]	26	26	—	81	76	5
Total operating and maintenance expense	$ 196	$ 204	$ (8)	$ 609	$ 668	$ (59)

(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 and nine months ended September 30, 2015 compared to the same period in 2014, consisted of the following:

	Three Months Ended September 30, 2015 Increase (Decrease)	Nine Months Ended September 30, 2015 Increase (Decrease)
Baseline		
Labor, other benefits, contracting and materials	$ (2)	$ (1)
Storm-related costs	(18)[(a)]	(78)[(b)]
Pension and non-pension postretirement benefits expense	1	2
Merger and integration costs	1	4
Uncollectible accounts expense	2	(3)
Other	8	12
	(8)	(64)
Regulatory required programs		
Smart meter	(2)	(3)
Energy efficiency	2	8
Other	—	—
	—	5
Increase (Decrease) in operating and maintenance expense	$ (8)	$ (59)

(a) Reflects a reduction of $17 million in incremental storm costs in the third quarter of 2015 as a result of the significant 2014 storms.
(b) Reflects a reduction of $68 million in incremental storm costs during 2015 primarily as a result of the February 5, 2014 ice storm.

Depreciation and Amortization Expense

The increase in depreciation and amortization expense for the three and nine months ended September 30, 2015 compared to the same periods in 2014 primarily reflects ongoing capital expenditures.

Taxes Other Than Income

Taxes other than income for the three and nine months ended September 30, 2015 compared to the same periods in 2014 remained relatively consistent.

Interest Expense, Net

Interest expense, net for the three and nine months ended September 30, 2015 compared to the same periods in 2014 remained relatively consistent.

Other, Net

Other, net for the three and nine months ended September 30, 2015 compared to the same periods in 2014 remained relatively consistent.

Effective Income Tax Rate

PECO’s effective income tax rate was 29.1% and 23.6% for the three months ended September 30, 2015 and 2014, respectively. PECO’s effective income tax rate was 29.0% and 24.3% for the nine months ended September 30, 2015 and 2014, respectively. See Note 12—Income Taxes of the Combined Notes to the Consolidated Financial Statements for further discussion of the change in effective income tax rate.

PECO Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	3,940	3,551	11.0%	(2.3)%	10,929	10,200	7.1%	(0.4)%
Small commercial & industrial	2,219	2,096	5.9%	1.0%	6,306	6,098	3.4%	0.6%
Large commercial & industrial	4,227	4,086	3.5%	0.7%	11,744	11,604	1.2%	(0.1)%
Public authorities & electric railroads	224	241	(7.1)%	(7.1)%	667	722	(7.6)%	(7.6)%
Total retail deliveries	10,610	9,974	6.4%	(0.5)%	29,646	28,624	3.6%	(0.2)%

Number of Electric Customers	As of September 30, 2015	As of September 30, 2014
Residential	1,439,951	1,429,293
Small commercial & industrial	148,920	149,172
Large commercial & industrial	3,093	3,103
Public authorities & electric railroads	9,801	9,737
Total	1,601,765	1,591,305

Electric Revenue	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change
Retail Sales[(a)]						
Residential	$ 461	$ 413	11.6%	$ 1,276	$ 1,195	6.8%
Small commercial & industrial	113	107	5.6%	330	319	3.4%
Large commercial & industrial	58	52	11.5%	166	169	(1.8)%
Public authorities & electric railroads	8	7	14.3%	23	23	—%
Total retail	640	579	10.5%	1,795	1,706	5.2%
Other revenue[(b)]	51	55	(7.3)%	155	165	(6.1)%
Total electric revenue	$ 691	$ 634	9.0%	$ 1,950	$ 1,871	4.2%

(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.

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PECO Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change	Weather - Normal % Change
Retail Delivery								
Retail sales[a]	3,639	3,893	(6.5)%	(3.2)%	45,734	44,487	2.8%	3.2%
Transportation and other	7,457	5,750	29.7%	17.5%	21,585	20,124	7.3%	2.9%
Total gas deliveries	11,096	9,643	15.1%	9.3%	67,319	64,611	4.2%	3.1%

Number of Gas Customers	As of September 30, 2015	As of September 30, 2014
Residential	465,023	459,678
Commercial & industrial	42,544	42,008
Total retail	507,567	501,686
Transportation	837	866
Total	508,404	502,552

Gas Revenue	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change
Retail Sales						
Retail sales[a]	$ 42	$ 54	(22.2)%	$ 410	$ 444	(7.7)%
Transportation and other	7	5	40.0%	26	28	(7.1)%
Total gas revenue	$ 49	$ 59	(16.9)%	$ 436	$ 472	(7.6)%

(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.

Results of Operations — BGE

	Three Months Ended September 30, 2015	2014	Favorable (Unfavorable) Variance	Nine Months Ended September 30, 2015	2014	Favorable (Unfavorable) Variance
Operating revenue	$ 725	$ 697	$ 28	$2,388	$2,404	$ (16)
Purchased power and fuel	311	297	(14)	1,037	1,094	57
Revenue net of purchased power and fuel[(a)]	414	400	14	1,351	1,310	41
Other operating expenses						
Operating and maintenance	169	165	(4)	499	541	42
Depreciation and amortization	79	78	(1)	271	275	4
Taxes other than income	57	55	(2)	169	168	(1)
Total other operating expenses	305	298	(7)	939	984	45
Gain on sale	1	—	1	1	—	1
Operating income	110	102	8	413	326	87
Other income and (deductions)						
Interest expense, net	(25)	(26)	1	(73)	(81)	8
Other, net	4	4	—	13	14	(1)
Total other income and (deductions)	(21)	(22)	1	(60)	(67)	7
Income before income taxes	89	80	9	353	259	94
Income taxes	35	31	(4)	141	103	(38)
Net income	54	49	5	212	156	56
Preference stock dividends	3	3	—	10	10	—
Net income attributable to common shareholder	$ 51	$ 46	$ 5	$ 202	$ 146	$ 56

(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 September 30, 2015, Compared to Three Months Ended September 30, 2014. BGE's net income attributable to common shareholder for the three months ended September 30, 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 lower storm costs in the BGE service territory, which is included in operating and maintenance expense.

Nine Months Ended September 30, 2015, Compared to Nine Months Ended September 30, 2014. BGE's net income attributable to common shareholder for the nine months ended September 30, 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 a reduction in bad debt expense and lower storm costs in the BGE service territory, which are included 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 customers are subject to periodic adjustments that are designed to recover or refund the difference between the actual cost of purchased electric power and purchased natural gas and the amount included in rates in accordance with the MDPSC's market-based SOS and gas commodity programs, respectively.

The number of customers electing to select a competitive 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.

Retail deliveries purchased from competitive electric generation and natural gas suppliers (as a percentage of kWh and mmcf sales, respectively) for the three and nine months ended September 30, 2015, compared to the same period in 2014, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Electric	60%	60%	59%	60%
Natural Gas	76%	73%	54%	55%

Retail customers purchasing electric generation and natural gas from competitive electric generation and natural gas suppliers at September 30, 2015 and 2014 consisted of the following:

	September 30, 2015		September 30, 2014	
	Number of customers	% of total retail customers	Number of customers	% of total retail customers
Electric	346,400	28%	369,300	30%
Natural Gas	154,900	24%	161,500	25%

The changes in BGE's operating revenue net of purchased power and fuel expense for the three and nine months ended September 30, 2015, compared to the same period in 2014, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)			Nine Months Ended September 30, Increase (Decrease)		
	Electric	Gas	Total	Electric	Gas	Total
Distribution rate increase	$ 2	$ 4	$ 6	$ 12	$ 25	$ 37
Regulatory required programs	7	—	7	8	2	10
Other	(1)	2	1	(4)	(2)	(6)
Total increase	$ 8	$ 6	$ 14	$ 16	$ 25	$ 41

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 and nine months ended September 30, 2015 compared to the same period in 2014 consisted of the following:

Heating and Cooling Degree-Days	2015	2014	Normal	% Change	
Three Months Ended September 30,				From 2014	From Normal
Heating Degree-Days	46	82	81	(43.9)%	(43.2)%
Cooling Degree-Days	592	484	593	22.3%	(0.2)%
Nine Months Ended September 30,					
Heating Degree-Days	3,418	3,439	2,985	(0.6)%	14.5%
Cooling Degree-Days	909	717	849	26.8%	7.1%

Distribution Rate Increase. The increase in distribution rates for the three and nine months ended September 30, 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 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 in BGE's Consolidated Statements of Operations and Comprehensive Income.

Other. 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 and nine months ended September 30, 2015 compared to the same period in 2014, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Labor, other benefits, contracting and materials	$ 4	$ —
Storm-related costs	(5)	(23)
Uncollectible accounts expense	(3)	(23)
Other	8	4
Increase (Decrease) in operating and maintenance expense	$ 4	$ (42)

Conduit Lease with City of Baltimore

On September 23, 2015, the Baltimore City Board of Estimates approved an increase in rental fees for access to the Baltimore City conduit system to be effective November 1, 2015, which will result in an increase to operating and maintenance expense of $30 million in 2016 subject to an annual increase based on the Consumer Price Index. BGE will seek recovery of this incremental expense in its next base rate case proceeding. On October 16, 2015, BGE filed a lawsuit against the City in the Circuit Court for Baltimore City to protect its customers from any improper use by the City of the conduit fee revenues and to place constraints on the City’s ability to set the conduit fee in the future.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2015 compared to the same period in 2014 remained relatively consistent.

Depreciation and amortization expense decreased for the nine months ended September 30, 2015 compared to the same period in 2014 primarily due to a reduction in regulatory asset amortization related to demand response programs and revised recovery periods for certain regulatory assets that became effective in January 2015 in accordance with the MDPSC approved 2014 electric and natural gas distribution rate case orders.

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 for the three and nine months ended September 30, 2015 compared to the same periods in 2014 remained relatively consistent.

Interest Expense, Net

The decrease in interest expense, net for the three and nine months ended September 30, 2015, compared to the same periods in 2014, consisted of the following:

	Three Months Ended September 30, Increase (Decrease)	Nine Months Ended September 30, Increase (Decrease)
Interest expense on debt (including financing trusts)	$ (1)	$ (3)
Interest expense related to capitalization of interest / AFUDC	(1)	(2)
Interest expense related to uncertain tax positions	—	(1)
Other	1	(2)
Increase (Decrease) in interest expense, net	$ (1)	$ (8)

Effective Income Tax Rate

BGE’s effective income tax rate was 39.3% and 38.8% for the three months ended September 30, 2015 and 2014, respectively, and 39.9% and 39.8% for the nine months ended September 30, 2015 and 2014, respectively. See Note 12 — Income Taxes of the Combined Notes to Consolidated Financial Statements for further discussion of the change in effective income tax rate.

BGE Electric Operating Statistics and Revenue Detail

Retail Deliveries to Customers (in GWhs)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change	Weather - Normal % Change
Retail Deliveries[(a)]								
Residential	3,458	3,291	5.1%	n.m.	10,266	10,023	2.4%	n.m.
Small commercial & industrial	788	805	(2.1)%	n.m.	2,413	2,343	3.0%	n.m.
Large commercial & industrial	3,829	3,818	0.3%	n.m.	10,735	10,880	(1.3)%	n.m.
Public authorities & electric railroads	75	79	(5.1)%	n.m.	224	236	(5.1)%	n.m.
Total electric deliveries	8,150	7,993	2.0%	n.m.	23,638	23,482	0.7%	n.m.

Number of Electric Customers	As of September 30, 2015	As of September 30, 2014
Residential	1,132,836	1,123,644
Small commercial & industrial	112,888	112,580
Large commercial & industrial	11,863	11,707
Public authorities & electric railroads	286	290
Total	1,257,873	1,248,221

Electric Revenue	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change
Retail Sales[(a)]						
Residential	$ 379	$ 348	8.9%	$ 1,131	$ 1,077	5.0%
Small commercial & industrial	70	72	(2.8)%	208	208	—%
Large commercial & industrial	122	134	(9.0)%	351	377	(6.9)%
Public authorities & electric railroads	9	8	12.5%	24	24	—%
Total retail	580	562	3.2%	1,714	1,686	1.7%
Other revenue	75	69	8.7%	194	207	(6.3)%
Total electric revenue	$ 655	$ 631	3.8%	$ 1,908	$ 1,893	0.8%

(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.

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BGE Gas Operating Statistics and Revenue Detail

Deliveries to Customers (in mmcf)	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Weather - Normal % Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change	Weather - Normal % Change
Retail Deliveries[b]								
Retail sales	11,719	10,257	14.3%	n.m.	72,481	71,479	1.4%	n.m.
Transportation and other	612	304	101.3%	n.m.	4,521	7,508	(39.8)%	n.m.
Total gas deliveries	12,331	10,561	16.8%	n.m.	77,002	78,987	(2.5)%	n.m.

Number of Gas Customers	As of September 30, 2015	As of September 30, 2014
Residential	613,571	610,750
Commercial & industrial	43,885	43,963
Total	657,456	654,713

Gas Revenue	Three Months Ended September 30, 2015	Three Months Ended September 30, 2014	% Change	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	% Change
Retail Sales[b]						
Retail sales	$ 66	$ 62	6.5%	$ 450	$ 439	2.5%
Transportation and other[c]	4	4	—%	30	72	(58.3)%
Total gas revenue	$ 70	$ 66	6.1%	$ 480	$ 511	(6.1)%

(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 612 mmcfs ($3 million) and 304 mmcfs ($2 million) for the three months ended September 30, 2015 and 2014, respectively and 4,521 mmcfs ($28 million) and 7,508 mmcfs ($60 million) for the nine months ended September 30, 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 syndicated 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 syndicated revolving credit facilities expire in 2018 and 2019. In addition, Generation has $0.5 billion in bilateral credit facilities with banks which have various expiration dates between December 2015 and October 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.

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 11 — 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, and management of the net 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 September 30, 2015 may be as much as $820 million, of which approximately $300 million would be attributable to ComEd after consideration of Exelon's agreement to hold ComEd harmless. Exelon expects to deposit approximately $260 million related to the termination of Exelon's investment in one of the three like-kind exchange properties within the next twelve months. Interest will continue to accrue until such time as payment is made. An appeal of an adverse decision in the Tax Court would necessitate either the posting of a bond or the payment of the tax and interest for the tax years before the court. A final appellate decision could take several years.

- Exelon, Generation, and ComEd expect to receive tax refunds of approximately $430 million, $195 million, and $265 million, respectively, in 2015. PECO expects to make tax payments of approximately $7 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 nine months ended September 30, 2015 and 2014:

	Nine Months Ended September 30,		
	2015(c)	2014	Variance
Net income	$1,959	$1,725	$ 234
Add (subtract):			
Non-cash operating activities[a]	3,900	4,200	(300)
Gain on consolidation and acquisitions of businesses	—	(268)	268
Pension and other postretirement benefit contributions	(430)	(516)	86
Income taxes	300	72	228
Changes in working capital and other noncurrent assets and liabilities[b]	(387)	(976)	589
Option premiums received, net	27	21	6
Counterparty collateral received (posted), net	305	(615)	920
Net cash flows provided by operations	$5,674	$3,643	$2,031

(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 nine months ended September 30, 2015 and 2014 by Registrant were as follows:

	Nine Months Ended September 30,	
	2015	2014
Exelon [a]	$5,674	$3,643
Generation [a]	3,206	1,784
ComEd	1,346	849
PECO	567	504
BGE	696	625

(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.

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 nine months ended September 30, 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 nine months ended September 30, 2015 and 2014, Generation had net collections/(payments) of counterparty collateral of $376 million and $(634) million, respectively, primarily due to market conditions that resulted in changes to Generation's net mark-to-market position.
- During the nine months ended September 30, 2015 and 2014, Generation had net collections of approximately $27 million and $21 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

- During the nine months ended September 30, 2015 and 2014, ComEd's payables for Generation energy purchases decreased by $(20) million and $(38) million, respectively, and payables to other energy suppliers for energy purchases increased by $5 million and $58 million, respectively.
- During the nine months ended September 30, 2015 and 2014, ComEd posted $41 million and $1 million of cash collateral to PJM, respectively. ComEd's collateral posted with PJM has increased year over year primarily due to higher RPM credit requirements and higher PJM billings resulting from increased load being served by ComEd as a result of City of Chicago customers switching back to ComEd.

PECO

- During the nine months ended September 30, 2015 and 2014, PECO's payables to Generation for energy purchases increased/(decreased) by $4 million and $(17) million, respectively, and payables to other electric and gas suppliers for energy purchases decreased by $(21) million and $(12) million, respectively.

BGE

- During the nine months ended September 30, 2015 and 2014, BGE's payables to Generation for energy purchases increased/(decreased) by $(13) million and $7 million, respectively, and payables to other electric and gas suppliers for energy purchases decreased by $(25) million and $(27) million, respectively.

Cash Flows from Investing Activities

Cash flows used in investing activities for the nine months ended September 30, 2015 and 2014 by Registrant were as follows:

	Nine Months Ended September 30,	
	2015	2014
Exelon [(a)]	$(5,689)	$(3,376)
Generation [(a)]	(3,020)	(1,431)
ComEd	(1,646)	(1,148)
PECO	(425)	(452)
BGE	(491)	(480)

(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 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 $346 million of anticipated expenditures remaining through 2019 to fund anticipated planned capital and operating needs of the associated companies.

Generation has executed, or expects to execute, several construction and services contracts. As of September 30, 2015, the total estimated remaining construction expenditures for these projects are approximately $1.3 billion and achievement of commercial operations is expected between 2015 and 2018 for all these projects.

Capital expenditures by Registrant for the nine months ended September 30, 2015 and 2014 and projected amounts for the full year 2015 are as follows:

	Projected Full Year 2015[e]	Nine Months Ended September 30,	
		2015	2014
Exelon[a]	$ 7,600	$5,443	$4,114
Generation[a][b]	3,850	2,774	1,961
ComEd[c]	2,425	1,670	1,173
PECO	600	435	461
BGE	675	506	458
Other[d]	50	58	61

(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) Generation's capital expenditures for the projected full year 2015 includes nuclear fuel of $1.3 billion and growth expenditures of $1.2 billion.
(c) The projected capital expenditures include approximately $665 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.

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 through 2016 associated with the CIP V.5 compliance implementation project.

Generation

Approximately 35% and 5% 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 95% 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.

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.

Cash Flows from Financing Activities

Cash flows provided by (used in) financing activities for the nine months ended September 30, 2015 and 2014 by Registrant were as follows:

	Nine Months Ended September 30,	
	2015	2014
Exelon [(a)]	$ 5,402	$ 887
Generation [(a)]	(421)	(300)
ComEd	285	307
PECO	(140)	77
BGE	(242)	(149)

(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.

PHI Merger Financing

As of September 30, 2015, through the issuance of $5.4 billion of debt (including $1.15 billion of junior subordinated notes in the form of 23 million equity units), the issuance of $1.9 billion of common stock, and cash proceeds of $1.8 billion from asset sales primarily at Generation (after-tax proceeds of approximately $1.4 billion), Exelon has sufficient cash to fund the all-cash purchase price, acquisition and integration related costs, and merger commitments. See Note 11—Debt and Credit Agreements and Note 17—Common Stock for further information on the debt and equity issuances. See Note 4—Merger and Acquisitions of the Exelon 2014 Form 10-K for further information on the asset sales.

Debt

See Note 11 — 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 nine months ended September 30, 2015 and 2014 by Registrant were as follows:

	Nine Months Ended September 30,	
	2015	2014
Exelon [(a)]	$ 819	$1,214
Generation [(a)]	2,368	855
ComEd	226	230
PECO	209	240
BGE [(b)]	126	10

(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.

Third Quarter 2015 Dividend

On July 28, 2015, the Exelon Board of Directors declared a third quarter 2015 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on September 10, 2015, to shareholders of record of Exelon at the end of the day on August 14, 2015.

Fourth Quarter 2015 Dividend

On October 27, 2015, the Exelon Board of Directors declared a third quarter 2015 regular quarterly dividend of $0.31 per share on Exelon's common stock payable on December 10, 2015, to shareholders of record of Exelon at the end of the day on November 13, 2015.

Short-Term Borrowings

During the nine months ended September 30, 2015, ComEd and BGE issued (repaid) $300 million and $(70) million of commercial paper, respectively, and Generation issued $15 million in short-term notes payable. During the nine months ended September 30, 2014, ComEd and BGE issued (repaid) $344 million and $(115) million of commercial paper, respectively, and Generation repaid $8 million in short-term notes payable.

Contributions from Parent/Member

During the nine months ended September 30, 2015, Generation, ComEd, PECO and BGE received $55 million, $75 million, $16 million, and $6 million from Parent (Exelon), respectively. During the nine months ended September 30, 2014, Generation, ComEd and PECO received $55 million, $168 million and $24 million from Parent (Exelon), respectively.

Other

For the nine months ended September 30, 2015, other financing activities primarily consists of debt issuance costs. See Note 11 — 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 $6.8 billion was available as of September 30, 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 third 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, ComEd, PECO or BGE lost its investment grade credit rating as of September 30, 2015, it would have been required to provide incremental collateral as follows:

	Incremental Collateral Required (in millions)	Available Credit Facility Capacity Prior to Any Incremental Collateral (in millions)
Generation [(a)]	$ 2,100	$ 4,841
ComEd	17	394
PECO [(b)]	18	599
BGE [(c)]	34	550

(a) Collateral obligations for derivatives, nonderivatives, normal purchase normal sales contracts and applicable payables and receivables, net of contractual right of offset under master netting agreements.
(b) Related to PECO's natural gas procurement contracts. No collateral would be required pursuant to PJM's credit policy.
(c) $6 million pursuant to PJM's credit policy and collateral of $28 million related to BGE's natural gas procurement contracts.

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 the issuance of letters of credit. See Note 11 — Debt and Credit Agreements of the Combined Notes to the Consolidated Financial Statements for further information regarding the Registrants' credit facilities.

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The following table reflects the Registrants' commercial paper programs supported by the revolving credit agreements and bilateral credit agreements at September 30, 2015:

Commercial Paper Programs

Commercial Paper Issuer	Maximum Program Size	Outstanding Commercial Paper at September 30, 2015	Average Interest Rate on Commercial Paper Borrowings for the nine months ended September 30, 2015
Exelon Corporate	$ 500	$ —	—%
Generation	5,600	—	0.49%
ComEd	1,000	604	0.52%
PECO	600	—	—%
BGE	600	50	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

					Available Capacity at September 30, 2015	
Borrower	Facility Type	Aggregate Bank Commitment(a)	Facility Draws	Outstanding Letters of Credit(b)	Actual	To Support Additional Commercial Paper(c)
Exelon Corporate	Syndicated Revolver	$ 500	$ —	$ 26	$ 474	$ 474
Generation (d)	Syndicated Revolver	5,300	—	599	4,701	4,701
Generation	Bilaterals	500	—	360	140	54
ComEd	Syndicated Revolver	1,000	—	2	998	394
PECO	Syndicated Revolver	600	—	1	599	599
BGE	Syndicated Revolver	600	—	—	600	550

(a) Excludes $123 million of credit facility agreements arranged with minority and community banks at Generation, ComEd, PECO and BGE. These facilities expired on October 16, 2015 and were renewed at the same amount through October 14, 2016. These facilities are solely utilized to issue letters of credit. See Note 11 — 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.
(d) Excludes ExGen Texas Power Financing's $15.5 million of borrowed debt on its revolving credit facility.

As of September 30, 2015, there were no borrowings under the Registrants' credit facilities.

On October 23, 2015, a $100 million bilateral CENG credit facility was amended and extended for an additional two years. This facility has been utilized by CENG to fund working capital and capital projects. This facility does not back Generation's commercial paper program.

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-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 nine months ended September 30, 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 September 30, 2015, the interest coverage ratios at the Registrants were as follows:

	Exelon	Generation	ComEd	PECO	BGE
Interest coverage ratio	8.99	12.42	7.40	9.49	10.34

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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for additional information on collateral provisions.

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 September 30, 2015, are presented in the following table:

	Three Months Ended September 30, 2015		As of September 30, 2015
Participant	Maximum Contributed	Maximum Borrowed	Contributed (Borrowed)
Generation	$ —	$ 1,310	$ (1,205)
PECO	—	81	(55)
BSC	—	356	(295)
Exelon Corporate	1,579	N/A	1,555

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 and CENG's NDT fund investment policies which outline investment guidelines for the trusts. See Note 13 — 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 September 30, 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 September 30, 2015, PECO had $1.1 billion available in long-term debt financing authority from the PAPUC. As of September 30, 2015, BGE had $1.4 billion available in long-term financing authority from MDPSC.

As of September 30, 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 19 — Commitments and Contingencies of the Combined Notes to Consolidated Financial Statements for discussion of the Registrants' commitments.

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.

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 September 30, 2015, the proportion of expected generation hedged is 97%-100%, 81%-84% and 51%-54% 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 September 30, 2015 market conditions and hedged position would be a $10 million increase in pre-tax net income for 2015 and a decrease in pre-tax net income of approximately $140 million and $500 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.

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 1,913 GWhs and 5,378 GWhs for the three and nine months ended September 30, 2015, respectively, and 3,006 GWhs and 8,129 GWhs for the three and nine months ended September 30, 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 nine months ended September 30, 2015 resulted in pre-tax gains of $3 million due to net mark-to-market losses of $5 million and realized gains of $8 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 $0.2 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 nine months ended September 30, 2015 of $7,041 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 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 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 19 — 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 10 — 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 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 10 — 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 10 — 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 September 30, 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 10 — 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 September 30, 2015 and December 31, 2014.

	Generation	ComEd	Exelon
Total mark-to-market energy contract net assets (liabilities) at December 31, 2014[a]	$ 1,712	$ (207)	$ 1,505
Total change in fair value during 2015 of contracts recorded in results of operations	355	—	355
Reclassification to realized at settlement of contracts recorded in results of operations	(106)	—	(106)
Reclassification to realized at settlement from accumulated OCI	(2)	—	(2)
Changes in fair value — energy derivatives[b]	—	(36)	(36)
Changes in allocated collateral	(373)	—	(373)
Changes in net option premium paid/(received)	(27)	—	(27)
Option premium amortization	(18)	—	(18)
Other balance sheet reclassifications[c]	15	—	15
Total mark-to-market energy contract net assets (liabilities) at September 30, 2015[a]	$ 1,556	$ (243)	$ 1,313

(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 September 30, 2015, ComEd recorded a $243 million regulatory asset related to its mark-to-market derivative liabilities with unaffiliated suppliers. As of September 30, 2015, ComEd also recorded $44 million of decreases in fair value and $8 million of realized losses due to settlements associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.
(c) Other balance sheet reclassifications include derivative contracts acquired or sold by Generation through upfront payments or receipts of cash, excluding option premiums.

Fair Values. The following tables present maturity and source of fair value for Exelon, Generation and ComEd mark-to-market commodity contract net assets (liabilities). The tables provide two fundamental pieces of information. First, the tables provide the source of fair value used in determining the carrying amount of the Registrants' total mark-to-market net assets (liabilities), net of allocated collateral. Second, the tables show the maturity, by year, of the Registrants' commodity contract net assets (liabilities), net of allocated collateral, giving an indication of when these mark-to-market amounts will settle and either generate or require cash. See Note 9 — 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						
	2015	2016	2017	2018	2019	2020 and Beyond	Total Fair Value
Normal operations, commodity derivative contracts[a][b]							
Actively quoted prices (Level 1)	$ (48)	$ (43)	$ 7	$(23)	$(21)	$ (8)	$ (136)
Prices provided by external sources (Level 2)	203	298	26	7	(10)	(6)	518
Prices based on model or other valuation methods (Level 3)[c]	120	539	327	52	(27)	(80)	931
Total	$275	$794	$360	$ 36	$(58)	$ (94)	$ 1,313

(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 $1,033 million at September 30, 2015.
(c) Includes ComEd's net assets (liabilities) associated with the floating-to-fixed energy swap contracts with unaffiliated suppliers.

Generation

	Maturities Within						
	2015	2016	2017	2018	2019	2020 and Beyond	Total Fair Value
Normal operations, commodity derivative contracts[a][b]							
Actively quoted prices (Level 1)	$ (48)	$ (43)	$ 7	$(23)	$(21)	$ (8)	$ (136)
Prices provided by external sources (Level 2)	203	298	26	7	(10)	(6)	518
Prices based on model or other valuation methods (Level 3)	128	560	348	74	(6)	70	1,174
Total	$283	$815	$381	$ 58	$(37)	$ 56	$ 1,556

(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 $1,033 million at September 30, 2015.

ComEd

	Maturities Within						
	2015	2016	2017	2018	2019	2020 and Beyond	Total Fair Value
Prices based on model or other valuation methods[a] (Level 3)	$ (8)	$(21)	$(21)	$(22)	$(21)	$ (150)	$ (243)

(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 10 — Derivative Financial Instruments of the Combined Notes to Consolidated Financial Statements for a detailed discussion of credit risk, collateral, and contingent related features.

Generation

The following tables provide information on Generation's credit exposure for all derivative instruments, normal purchase normal sales agreements, and applicable payables and receivables, net of collateral and instruments that are subject to master netting agreements, as of September 30, 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 $24 million, $33 million and $27 million, respectively. See Note 25 — Related Party Transactions of the Exelon 2014 Form 10-K for additional information.

Rating as of September 30, 2015	Total Exposure Before Credit Collateral	Credit Collateral(a)	Net Exposure	Number of Counterparties Greater than 10% of Net Exposure	Net Exposure of Counterparties Greater than 10% of Net Exposure
Investment grade	$ 1,463	$ 18	$ 1,445	1	$ 444
Non-investment grade	55	15	40	—	—
No external ratings					
Internally rated — investment grade	535	—	535	—	—
Internally rated — non-investment grade	53	5	48	—	—
Total	$ 2,106	$ 38	$ 2,068	1	$ 444

	Maturity of Credit Risk Exposure			
Rating as of September 30, 2015	Less than 2 Years	2-5 Years	Exposure Greater than 5 Years	Total Exposure Before Credit Collateral
Investment grade	$ 1,028	$ 414	$ 21	$ 1,463
Non-investment grade	38	13	4	55
No external ratings				
Internally rated — investment grade	436	71	28	535
Internally rated — non-investment grade	50	3	—	53
Total	$ 1,552	$ 501	$ 53	$ 2,106

Net Credit Exposure by Type of Counterparty	As of September 30, 2015
Financial institutions	$ 260
Investor-owned utilities, marketers, power producers	867
Energy cooperatives and municipalities	908
Other	33
Total	$ 2,068

(a) As of September 30, 2015, credit collateral held from counterparties where Generation had credit exposure included $13 million of cash and $25 million of letters of credit.

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 10 — 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 10 — 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 10 — 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 10 — 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 11 — Debt and Credit Agreements of the Combined Notes to Consolidated Financial Statements for additional information.

As of September 30, 2015, Generation had cash collateral of $1,065 million posted and cash collateral held of $21 million for external counterparties, of which $1,033 million and $7 million in net cash 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 September 30, 2015, $4 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 19 — 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 September 30, 2015, ComEd held no 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 10 — 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 September 30, 2015, PECO was not required to post collateral under its energy and natural gas procurement contracts. See Note 10 — 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 September 30, 2015, BGE was not required to post collateral under its natural gas procurement contracts. See Note 10 — 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.

Long-Term Leases (Exelon)

Exelon's Consolidated Balance Sheet, as of September 30, 2015, included a $348 million net investment in coal-fired plants in Georgia subject to long-term leases. This investment represents the estimated residual value of leased assets at the end of the respective lease terms of $639 million, less unearned income of $291 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 September 30, 2015, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $752 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 $3 million decrease in Exelon Consolidated pre-tax income for the nine months ended September 30, 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 September 30, 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 $434 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.

Item 4. Controls and Procedures

During the third 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 0.58% and 1.19%, respectively, of Exelon's and Generation's related consolidated balance sheet amounts as of September 30, 2015. The total revenues related to Integrys are 6.65% and 10.32%, respectively, of Exelon's and Generation's related consolidated statements of operations and comprehensive income amounts for the three months ended September 30, 2015. The total revenues related to Integrys are 7.40% and 11.35%, respectively, of Exelon's and Generation's related consolidated statements of operations and comprehensive income amounts for the nine months ended September 30, 2015.

Accordingly, as of September 30, 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 third quarter of 2015 that have materially affected, or are reasonably likely to materially affect, any of the Registrant's internal control over financial reporting.

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 19 — 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 September 30, 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 No.	Description
4.1	One Hundred and Twelfth Supplemental Indenture dated as of September 15, 2015 from PECO to U.S. Bank National Association, as trustee (File no. 000-16844, Form 8-K dated October 5, 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

Table of Contents

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 September 30, 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 September 30, 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

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	/s/ JONATHAN W. THAYER
Christopher M. Crane President and Chief Executive Officer (Principal Executive Officer) and Director	Jonathan W. Thayer Senior Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ DUANE M. DESPARTE	
Duane M. DesParte Senior Vice President and Corporate Controller (Principal Accounting Officer)	

October 30, 2015

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	/s/ BRYAN P. WRIGHT
Kenneth W. Cornew President and Chief Executive Officer (Principal Executive Officer)	Bryan P. Wright Senior Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ ROBERT M. AIKEN	
Robert M. Aiken Chief Accounting Officer (Principal Accounting Officer)	

October 30, 2015

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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	/s/ Joseph R. Trpik, Jr.
Anne R. Pramaggiore President and Chief Executive Officer (Principal Executive Officer)	Joseph R. Trpik, Jr. Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Gerald J. Kozel	
Gerald J. Kozel Vice President and Controller (Principal Accounting Officer)	

October 30, 2015

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	/s/ Phillip S. Barnett
Craig L. Adams President and Chief Executive Officer (Principal Executive Officer)	Phillip S. Barnett Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Scott A. Bailey	
Scott A. Bailey Vice President and Controller (Principal Accounting Officer)	

October 30, 2015

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.	/s/ David M. Vahos
Calvin G. Butler, Jr. Chief Executive Officer (Principal Executive Officer)	David M. Vahos Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)
/s/ Matthew N. Bauer	
Matthew N. Bauer Vice President and Controller (Principal Accounting Officer)	

October 30, 2015

Exhibit 31-1

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Christopher M. Crane, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CHRISTOPHER M. CRANE

President and Chief Executive Officer
(Principal Executive Officer)

Date: October 30, 2015

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Jonathan W. Thayer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JONATHAN W. THAYER

Senior Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: October 30, 2015

Exhibit 31-3

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Kenneth W. Cornew, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ KENNETH W. CORNEW
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 30, 2015

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Bryan P. Wright, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Exelon Generation Company, LLC;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ BRYAN P. WRIGHT

Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: October 30, 2015

Exhibit 31-5

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Anne R. Pramaggiore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ ANNE R. PRAMAGGIORE
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 30, 2015

Exhibit 31-6

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Joseph R. Trpik, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Commonwealth Edison Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ JOSEPH R. TRPIK, JR.

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 30, 2015

Exhibit 31-7

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Craig L. Adams, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CRAIG L. ADAMS
President and Chief Executive Officer
(Principal Executive Officer)

Date: October 30, 2015

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Phillip S. Barnett, certify that:

1. I have reviewed this quarterly report on Form 10-Q of PECO Energy Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ PHILLIP S. BARNETT

Senior Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 30, 2015

Exhibit 31-9

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, Calvin G. Butler, Jr., certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ CALVIN G. BUTLER, JR.
Chief Executive Officer
(Principal Executive Officer)

Date: October 30, 2015

CERTIFICATION PURSUANT TO RULE 13a-14(a) AND 15d-14(a) OF THE SECURITIES AND EXCHANGE ACT OF 1934

I, David M. Vahos, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Baltimore Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

/s/ DAVID M. VAHOS

Vice President, Chief Financial Officer and Treasurer
(Principal Financial Officer)

Date: October 30, 2015

Exhibit 32-1

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ CHRISTOPHER M. CRANE

Christopher M. Crane
President and Chief Executive Officer

Date: October 30, 2015

Exhibit 32-2

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Corporation for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Corporation.

/s/ JONATHAN W. THAYER

Jonathan W. Thayer
Senior Executive Vice President and Chief Financial Officer

Date: October 30, 2015

Exhibit 32-3

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ KENNETH W. CORNEW

Kenneth W. Cornew
President and Chief Executive Officer

Date: October 30, 2015

Exhibit 32-4

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Exelon Generation Company, LLC for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Exelon Generation Company, LLC.

/s/ BRYAN P. WRIGHT
Bryan P. Wright
Senior Vice President and Chief Financial Officer

Date: October 30, 2015

Exhibit 32-5

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ ANNE R. PRAMAGGIORE

Anne R. Pramaggiore
President and Chief Executive Officer

Date: October 30, 2015

Exhibit 32-6

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Commonwealth Edison Company for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Commonwealth Edison Company.

/s/ JOSEPH R. TRPIK, JR.

Joseph R. Trpik, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Date: October 30, 2015

Exhibit 32-7

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ CRAIG L. ADAMS

Craig L. Adams
President and Chief Executive Officer

Date: October 30, 2015

Exhibit 32-8

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of PECO Energy Company for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of PECO Energy Company.

/s/ PHILLIP S. BARNETT

Phillip S. Barnett
Senior Vice President, Chief Financial Officer and Treasurer

Date: October 30, 2015

Exhibit 32-9

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ CALVIN G. BUTLER, JR.
Calvin G. Butler, Jr.
Chief Executive Officer

Date: October 30, 2015

Exhibit 32-10

Certificate Pursuant to Section 1350 of Chapter 63 of Title 18 United States Code

The undersigned officer hereby certifies, as to the quarterly report on Form 10-Q of Baltimore Gas and Electric Company for the quarterly period ended September 30, 2015, that (i) the report fully complies with the requirements of section 13(a) or 15 (d) of the Securities Exchange Act of 1934, and (ii) the information contained in the report fairly presents, in all material respects, the financial condition and results of operations of Baltimore Gas and Electric Company.

/s/ DAVID M. VAHOS

David M. Vahos
Vice President, Chief Financial Officer and Treasurer

Date: October 30, 2015