EXELON CORP
Form 10-Q
October 30, 2015
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended 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	36-0938600

	Chicago, Illinois 60605-1028	
	(312) 394-4321	
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation)	23-0970240
	P.O. Box 8699	
	2301 Market Street	
	Philadelphia, Pennsylvania 19101-8699	
	(215) 841-4000	
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation)	52-0280210
	2 Center Plaza	
	110 West Fayette Street	
	Baltimore, Maryland 21201-3708	
	(410) 234-5000	

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

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

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

	Large Accelerated Filer	**Accelerated Filer**	**Non-accelerated Filer**	**Smaller Reporting Company**
Exelon Corporation	x			
Exelon Generation Company, LLC			x	
Commonwealth Edison Company			x	
PECO Energy Company			x	
Baltimore Gas and Electric Company			x	

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

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

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

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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

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FILING FORMAT

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

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon s 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 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.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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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

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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

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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

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions, shares in thousands)	Issued Shares	Common Stock	Treasury Stock	Retained Earnings	Accumulated Other Comprehensive Loss, net	Noncontrolling Interest	Preference Stock	Total Equity
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

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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

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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

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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

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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.

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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

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2015**	**2014**	**2015**	**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

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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

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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

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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

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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	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

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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

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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

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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

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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

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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
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.

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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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Unconsolidated Variable Interest Entities

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

The Registrants unconsolidated VIEs consist of:

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

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

- Equity investments in energy development projects, 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

(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

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(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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	Fair Value			
	Amount	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

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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
Fair Value

	Carrying Amount	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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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		December 31, 2014			
	Carrying	Fair Value			
	Amount	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	Fair Value			
	Amount	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	Fair Value			
	Amount	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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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	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

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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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on the utility Registrants Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of 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

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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, 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 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.

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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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Nine 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 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.

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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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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.

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(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	Three Months Ended September 30,			
		2015	2014	2015	2014
	Location	Gain (Loss) on Swaps		Gain (Loss) on Borrowings	
Generation	Interest expense(a)	$	$ (4)	$	$ 1
Exelon	Interest expense	16	(8)	13	(6)

	Income Statement	Nine Months Ended September 30,			
		2015	2014	2015	2014
	Location	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,

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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.

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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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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	
Three Months Ended September 30, 2015	**Income Statement Location**	**Generation Total Cash Flow Hedges**	**Exelon 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	
Nine Months Ended September 30, 2015	**Income Statement Location**	**Generation Total Cash Flow Hedges**	**Exelon 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	
Three Months Ended September 30, 2014	**Income Statement Location**	**Generation Total Cash Flow Hedges**	**Exelon 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
		Generation	Exelon
Nine Months Ended September 30, 2014	**Income Statement Location**	**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.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation				HoldCo	Exelon
Three Months Ended September 30, 2015	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**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)

	Generation				HoldCo	Exelon
Nine Months Ended September 30, 2015	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**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

	Generation				HoldCo	Exelon
Three Months Ended September 30, 2014	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**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, 2015	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 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

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

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.

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.

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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.

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(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.

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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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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(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

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(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.

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(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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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

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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%

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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%

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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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

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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.

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In the first quarter of 2014, Exelon entered into an agreement to terminate its investment in one of the three municipal-owned electric generation properties in exchange for a net early termination amount of $335 million. 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

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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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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		Other Postretirement Benefits	
	Three Months Ended September 30,		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		Other Postretirement Benefits	
	Nine Months Ended September 30,		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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension and Other Postretirement Benefit Costs	**2015**	**2014**	**2015**	**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:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Savings Plan Matching Contributions	**2015**	**2014**	**2015**	**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

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

termination benefits), the Registrants measure the obligation and record the expense at fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

Ongoing Severance Plans

The Registrants provide severance, health and welfare benefits under Exelon s ongoing severance benefit plans to terminated employees in the normal course of business. 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)

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(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	$					