EXELON CORP
Form 10-Q
July 29, 2015
Table of Contents

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 June 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 June 30, 2015 was:

Exelon Corporation Common Stock, without par value	861,617,731
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

Table of Contents

TABLE OF CONTENTS

		Page No.
FILING FORMAT		7
FORWARD-LOOKING STATEMENTS		7
WHERE TO FIND MORE INFORMATION		7
PART I.	FINANCIAL INFORMATION	8
ITEM 1.	FINANCIAL STATEMENTS	8
	Exelon Corporation	
	Consolidated Statements of Operations and Comprehensive Income	9
	Consolidated Statements of Cash Flows	10
	Consolidated Balance Sheets	11
	Consolidated Statement of Changes in Shareholders Equity	13
	Exelon Generation Company, LLC	
	Consolidated Statements of Operations and Comprehensive Income	14
	Consolidated Statements of Cash Flows	15
	Consolidated Balance Sheets	16
	Consolidated Statement of Changes in Equity	18
	Commonwealth Edison Company	
	Consolidated Statements of Operations and Comprehensive Income	19
	Consolidated Statements of Cash Flows	20
	Consolidated Balance Sheets	21
	Consolidated Statement of Changes in Shareholders Equity	23
	PECO Energy Company	
	Consolidated Statements of Operations and Comprehensive Income	24
	Consolidated Statements of Cash Flows	25
	Consolidated Balance Sheets	26
	Consolidated Statement of Changes in Shareholders Equity	28
	Baltimore Gas and Electric Company	
	Consolidated Statements of Operations and Comprehensive Income	29
	Consolidated Statements of Cash Flows	30
	Consolidated Balance Sheets	31
	Consolidated Statement of Changes in Shareholders Equity	33
	Combined Notes to Consolidated Financial Statements	34
	1. Basis of Presentation	34
	2. New Accounting Pronouncements	35
	3. Variable Interest Entities	37
	4. Mergers, Acquisitions and Dispositions	42
	5. Regulatory Matters	45
	6. Investment in Constellation Energy Nuclear Group, LLC	57
	7. Impairment of Long-Lived Assets	58

1

Table of Contents

		Page No.
	8. Implications of Potential Early Plant Retirements	60
	9. Fair Value of Financial Assets and Liabilities	61
	10. Derivative Financial Instruments	79
	11. Debt and Credit Agreements	95
	12. Income Taxes	100
	13. Nuclear Decommissioning	104
	14. Retirement Benefits	106
	15. Severance	108
	16. Changes in Accumulated Other Comprehensive Income	109
	17. Common Stock	114
	18. Earnings Per Share and Equity	115
	19. Commitments and Contingencies	115
	20. Supplemental Financial Information	129
	21. Segment Information	134
ITEM 2.	**MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**	141
	Exelon Corporation	141
	General	141
	Executive Overview	142
	Critical Accounting Policies and Estimates	167
	Results of Operations	167
	Liquidity and Capital Resources	195
	Contractual Obligations and Off-Balance Sheet Arrangements	205
ITEM 3.	**QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**	207
ITEM 4.	**CONTROLS AND PROCEDURES**	215
PART II.	**OTHER INFORMATION**	217
ITEM 1.	**LEGAL PROCEEDINGS**	217
ITEM 1A.	**RISK FACTORS**	217
ITEM 4.	**MINE SAFETY DISCLOSURES**	217
ITEM 6.	**EXHIBITS**	217
SIGNATURES		219
	Exelon Corporation	219
	Exelon Generation Company, LLC	219
	Commonwealth Edison Company	220
	PECO Energy Company	220
	Baltimore Gas and Electric Company	220

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities	
Exelon	Exelon Corporation
Generation	Exelon Generation Company, LLC
ComEd	Commonwealth Edison Company
PECO	PECO Energy Company
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

Table of Contents

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

Table of Contents

GLOSSARY OF TERMS AND ABBREVIATIONS

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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
PHI	Pepco Holdings, Inc.
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
PPL	PPL Holtwood, LLC
Price-Anderson Act	Price-Anderson Nuclear Industries Indemnity Act of 1957
PRP	Potentially Responsible Parties
PSEG	Public Service Enterprise Group Incorporated
PURTA	Pennsylvania Public Realty Tax Act
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act of 1976, as amended
REC	Renewable Energy Credit which is issued for each megawatt hour of generation from a qualified renewable energy source
Regulatory Agreement Units	Nuclear generating units whose decommissioning-related activities are subject to contractual elimination under regulatory accounting including the former ComEd units (Braidwood, Bryon, Dresden, LaSalle, Quad Cities) and the former PECO units (Limerick, Peach Bottom, Salem)
RES	Retail Electric Suppliers
RFP	Request for Proposal
Rider	Reconcilable Surcharge Recovery Mechanism
RGGI	Regional Greenhouse Gas Initiative
RMC	Risk Management Committee
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

Table of Contents

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.

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions, except per share data)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenues	$ 6,514	$ 6,024	$ 15,345	$ 13,261
Operating expenses				
Purchased power and fuel	2,449	2,346	6,919	6,352
Purchased power and fuel from affiliates		66		400
Operating and maintenance	2,042	2,166	4,123	4,024
Depreciation and amortization	602	590	1,212	1,154
Taxes other than income	294	288	598	580
Total operating expenses	5,387	5,456	12,852	12,510
Equity in losses of unconsolidated affiliates				(20)
Gain on sales of assets	7	13	8	18
Gain on consolidation and acquisition of businesses		261		261
Operating income	1,134	842	2,501	1,010
Other income and (deductions)				
Interest expense, net	(145)	(228)	(480)	(445)
Interest expense to affiliates	(10)	(10)	(21)	(20)
Other, net	(17)	230	64	330
Total other income and (deductions)	(172)	(8)	(437)	(135)
Income before income taxes	962	834	2,064	875
Income taxes	327	277	690	224
Equity in losses of unconsolidated affiliates	(2)		(2)	
Net income	633	557	1,372	651
Net income (loss) attributable to noncontrolling interest and preference stock dividends	(5)	35	41	39
Net income attributable to common shareholders	$ 638	$ 522	$ 1,331	$ 612
Comprehensive income, net of income taxes				
Net income	$ 633	$ 557	$ 1,372	$ 651
Other comprehensive income (loss), net of income taxes				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	(11)	(6)	(23)	(6)
Actuarial loss reclassified to periodic cost	55	38	110	72
Pension and non-pension postretirement benefit plans valuation adjustment		258	(29)	246
Unrealized gain (loss) on cash flow hedges	3	(48)	9	(73)
Unrealized gain on equity investments				11
Unrealized gain (loss) on foreign currency translation	3	4	(9)	(1)

Unrealized loss on marketable securities		1		1
Reversal of CENG equity method AOCI		(116)		(116)
Other comprehensive income	50	131	58	134
Comprehensive income	$ 683	$ 688	$ 1,430	$ 785
Average shares of common stock outstanding:				
Basic	863	860	862	860
Diluted	866	864	866	863
Earnings per average common share:				
Basic	$ 0.74	$ 0.61	$ 1.54	$ 0.71
Diluted	$ 0.74	$ 0.60	$ 1.54	$ 0.71
Dividends per common share	$ 0.31	$ 0.31	$ 0.62	$ 0.62

Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 1,372	$ 651
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	1,957	1,925
Impairment of long-lived assets	24	112
Gain on consolidation and acquisition of businesses		(268)
Gain on sales of assets	(8)	(18)
Deferred income taxes and amortization of investment tax credits	211	133
Net fair value changes related to derivatives	(507)	751
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(2)	(168)
Other non-cash operating activities	579	473
Changes in assets and liabilities:		
Accounts receivable	253	48
Inventories	159	(150)
Accounts payable, accrued expenses and other current liabilities	(668)	(358)
Option premiums received, net	22	21
Counterparty collateral received (posted), net	417	(606)
Income taxes	247	(16)
Pension and non-pension postretirement benefit contributions	(301)	(499)
Other assets and liabilities	214	(280)
Net cash flows provided by operating activities	3,969	1,751
Cash flows from investing activities		
Capital expenditures	(3,460)	(2,501)
Proceeds from nuclear decommissioning trust fund sales	3,314	4,219
Investment in nuclear decommissioning trust funds	(3,437)	(4,238)
Acquisition of businesses	(28)	(66)
Proceeds from sale of long-lived assets	145	32
Proceeds from termination of direct financing lease investment		335
Cash and restricted cash acquired from consolidations and acquisitions		129
Change in restricted cash	(3)	(40)
Other investing activities	(77)	(57)
Net cash flows used in investing activities	(3,546)	(2,187)
Cash flows from financing activities		
Changes in short-term borrowings	94	293
Issuance of long-term debt	5,907	2,100
Retirement of long-term debt	(1,708)	(1,191)
Distributions to noncontrolling interest of consolidated VIE		(415)
Dividends paid on common stock	(537)	(533)
Proceeds from employee stock plans	16	18
Other financing activities	(59)	(83)

Net cash flows provided by financing activities	3,713	189
Increase (decrease) in cash and cash equivalents	4,136	(247)
Cash and cash equivalents at beginning of period	1,878	1,609
Cash and cash equivalents at end of period	$ 6,014	$ 1,362

See the Combined Notes to Consolidated Financial Statements

10

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 6,014	$ 1,878
Restricted cash and cash equivalents	274	271
Accounts receivable, net		
Customer	3,227	3,482
Other	1,304	1,227
Mark-to-market derivative assets	1,405	1,279
Unamortized energy contract assets	156	254
Inventories, net		
Fossil fuel and emission allowances	364	579
Materials and supplies	1,068	1,024
Deferred income taxes	173	244
Regulatory assets	785	847
Assets held for sale	1	147
Other	654	865
Total current assets	15,425	12,097
Property, plant and equipment, net	53,935	52,087
Deferred debits and other assets		
Regulatory assets	5,976	6,076
Nuclear decommissioning trust funds	10,607	10,537
Investments	607	544
Goodwill	2,672	2,672
Mark-to-market derivative assets	811	773
Deferred income taxes	2	
Unamortized energy contracts assets	526	549
Pledged assets for Zion Station decommissioning	264	319
Other	1,388	1,160
Total deferred debits and other assets	22,853	22,630
Total assets[(a)]	$ 92,213	$ 86,814

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 543	$ 460
Long-term debt due within one year	226	1,802
Accounts payable	2,727	3,048
Accrued expenses	1,366	1,539
Payables to affiliates	8	8
Regulatory liabilities	409	310
Mark-to-market derivative liabilities	165	234
Unamortized energy contract liabilities	141	238
Other	941	1,123
Total current liabilities	6,526	8,762
Long-term debt	25,220	19,362
Long-term debt to financing trusts	648	648
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	13,309	13,019
Asset retirement obligations	7,550	7,295
Pension obligations	3,134	3,366
Non-pension postretirement benefit obligations	1,850	1,742
Spent nuclear fuel obligation	1,021	1,021
Regulatory liabilities	4,462	4,550
Mark-to-market derivative liabilities	595	403
Unamortized energy contract liabilities	166	211
Payable for Zion Station decommissioning	135	155
Other	2,528	2,147
Total deferred credits and other liabilities	34,750	33,909
Total liabilities[a]	67,144	62,681
Commitments and contingencies		
Shareholders equity		
Common stock (No par value, 2,000 shares authorized, 862 shares and 860 shares outstanding at June 30, 2015 and December 31, 2014, respectively)	16,755	16,709
Treasury stock, at cost (35 shares at both June 30, 2015 and December 31, 2014)	(2,327)	(2,327)
Retained earnings	11,704	10,910
Accumulated other comprehensive loss, net	(2,626)	(2,684)
Total shareholders equity	23,506	22,608
BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	1,370	1,332
Total equity	25,069	24,133

Total liabilities and shareholders equity	$ 92,213	$ 86,814

(a) Exelon s consolidated assets include $7,989 million and $8,160 million at June 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 $2,555 million and $2,723 million at June 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

Table of Contents

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				1,331		35	6	1,372
Long-term incentive plan activity	1,252	29						29
Employee stock purchase plan issuances	790	16						16
Tax benefit on stock compensation		1						1
Changes in equity of noncontrolling interest						3		3
Common stock dividends				(537)				(537)
Preference stock dividends							(6)	(6)
Other comprehensive income, net of income taxes					58			58
Balance, June 30, 2015	896,610	$ 16,755	$ (2,327)	$ 11,704	$ (2,626)	$ 1,370	$ 193	$ 25,069

See the Combined Notes to Consolidated Financial Statements

13

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2015**	**2014**	**2015**	**2014**
Operating revenues				
Operating revenues	$ 4,079	$ 3,588	$ 9,709	$ 7,644
Operating revenues from affiliates	153	201	365	535
Total operating revenues	4,232	3,789	10,074	8,179
Operating expenses				
Purchased power and fuel	1,848	1,766	5,274	4,774
Purchased power and fuel from affiliates	1	69	8	417
Operating and maintenance	1,149	1,255	2,311	2,194
Operating and maintenance from affiliates	159	158	308	305
Depreciation and amortization	255	254	509	466
Taxes other than income	124	118	246	223
Total operating expenses	3,536	3,620	8,656	8,379
Equity in losses of unconsolidated affiliates		(1)		(20)
Gain on sales of assets	7	12	6	18
Gain on consolidation and acquisition of businesses		261		261
Operating income	703	441	1,424	59
Other income and (deductions)				
Interest expense	(90)	(74)	(180)	(147)
Interest expense to affiliates, net	(9)	(12)	(21)	(25)
Other, net	(31)	216	62	300
Total other income and (deductions)	(130)	130	(139)	128
Income before income taxes	573	571	1,285	187
Income taxes (benefit)	181	199	407	(1)
Equity in losses of unconsolidated affiliates	(2)		(3)	
Net income	390	372	875	188
Net (loss) income attributable to noncontrolling interests	(8)	32	34	33
Net income attributable to membership interest	$ 398	$ 340	$ 841	$ 155
Comprehensive income, net of income taxes				
Net income	$ 390	$ 372	$ 875	$ 188
Other comprehensive income (loss), net of income taxes				
Unrealized gain (loss) on cash flow hedges	2	(45)	(3)	(70)
Unrealized gain on equity investments				11
Unrealized gain (loss) on foreign currency translation	3	4	(9)	(1)

Unrealized gain (loss) on marketable securities	1	2	1	(1)
Reversal of CENG equity method AOCI		(116)		(116)
Other comprehensive income (loss)	6	(155)	(11)	(177)
Comprehensive income	$ 396	$ 217	$ 864	$ 11

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(In millions)	**2015**	**2014**
Cash flows from operating activities		
Net income	$ 875	$ 188
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	1,255	1,242
Impairment of long-lived assets	(1)	88
Gain on consolidation and acquisitions of businesses		(268)
Gain on sales of assets	(6)	(18)
Deferred income taxes and amortization of investment tax credits	65	(15)
Net fair value changes related to derivatives	(396)	760
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(2)	(168)
Other non-cash operating activities	134	139
Changes in assets and liabilities:		
Accounts receivable	291	63
Receivables from and payables to affiliates, net	(11)	(20)
Inventories	134	(170)
Accounts payable, accrued expenses and other current liabilities	(485)	(273)
Option premiums received, net	22	21
Counterparty collateral (posted) received, net	440	(633)
Income taxes	27	72
Pension and non-pension postretirement benefit contributions	(122)	(210)
Other assets and liabilities	203	(56)
Net cash flows provided by operating activities	2,423	742
Cash flows from investing activities		
Capital expenditures	(1,764)	(1,103)
Proceeds from nuclear decommissioning trust fund sales	3,314	4,219
Investment in nuclear decommissioning trust funds	(3,437)	(4,238)
Acquisition of businesses	(28)	(66)
Proceeds from sale of long-lived assets	144	32
Change in restricted cash	(16)	(17)
Changes in Exelon intercompany money pool		44
Cash and restricted cash acquired from consolidations and acquisitions		129
Other investing activities	(63)	(14)
Net cash flows used in investing activities	(1,850)	(1,014)
Cash flows from financing activities		
Change in short-term borrowings	15	46
Issuance of long-term debt	1,307	300
Retirement of long-term debt	(39)	(538)
Retirement of long-term debt to affiliate	(550)	
Changes in Exelon intercompany money pool	638	190
Distribution to member	(2,262)	(235)
Distributions to noncontrolling interest of consolidated VIE		(415)

Other financing activities	(6)	(29)
Net cash flows used in financing activities	(897)	(681)
Decrease in cash and cash equivalents	(324)	(953)
Cash and cash equivalents at beginning of period	780	1,258
Cash and cash equivalents at end of period	$ 456	$ 305

See the Combined Notes to Consolidated Financial Statements

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 456	$ 780
Restricted cash and cash equivalents	174	158
Accounts receivable, net		
Customer	2,045	2,295
Other	299	318
Mark-to-market derivative assets	1,405	1,276
Receivables from affiliates	103	113
Unamortized energy contract assets	156	254
Inventories, net		
Fossil fuel and emission allowances	305	465
Materials and supplies	860	847
Deferred income taxes	188	327
Assets held for sale	1	147
Other	451	658
Total current assets	6,443	7,638
Property, plant and equipment, net	23,766	22,945
Deferred debits and other assets		
Nuclear decommissioning trust funds	10,607	10,537
Investments	183	104
Goodwill	47	47
Mark-to-market derivative assets	790	771
Prepaid pension asset	1,699	1,704
Pledged assets for Zion Station decommissioning	264	319
Unamortized energy contract assets	526	549
Deferred income taxes	2	3
Other	798	731
Total deferred debits and other assets	14,916	14,765
Total assets[a]	$ 45,125	$ 45,348

See the Combined Notes to Consolidated Financial Statements

16

Table of Contents

EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 40	$ 36
Long-term debt due within one year	89	58
Long-term debt to affiliates due within one year		556
Accounts payable	1,528	1,759
Accrued expenses	732	886
Payables to affiliates	98	107
Borrowings from Exelon intercompany money pool	638	
Mark-to-market derivative liabilities	145	214
Unamortized energy contract liabilities	141	238
Other	453	605
Total current liabilities	3,864	4,459
Long-term debt	7,974	6,709
Long-term debt to affiliate	938	943
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	6,009	6,034
Asset retirement obligations	7,399	7,146
Non-pension postretirement benefit obligations	922	915
Spent nuclear fuel obligation	1,021	1,021
Payables to affiliates	2,832	2,880
Mark-to-market derivative liabilities	392	105
Unamortized energy contract liabilities	166	211
Payable for Zion Station decommissioning	135	155
Other	817	719
Total deferred credits and other liabilities	19,693	19,186
Total liabilities[(a)]	32,469	31,297
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	8,951	8,951
Undistributed earnings	2,382	3,803
Accumulated other comprehensive loss, net	(47)	(36)
Total member s equity	11,286	12,718
Noncontrolling interest	1,370	1,333
Total equity	12,656	14,051

Total liabilities and equity	$ 45,125	$ 45,348

(a) Generation s consolidated assets include $7,949 million and $8,119 million at June 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 $2,435 million and $2,507 million at June 30, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Generation. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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		841		34	875
Changes in equity of noncontrolling interest				3	3
Distribution to member		(2,262)			(2,262)
Other comprehensive loss, net of income taxes			(11)		(11)
Balance, June 30, 2015	$ 8,951	$ 2,382	$ (47)	$ 1,370	$ 12,656

See the Combined Notes to Consolidated Financial Statements

18

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions)	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating revenues				
Operating revenues	$ 1,147	$ 1,128	$ 2,331	$ 2,261
Operating revenues from affiliates	1		2	1
Total operating revenues	1,148	1,128	2,333	2,262
Operating expenses				
Purchased power	269	204	586	416
Purchased power from affiliate	6	65	15	173
Operating and maintenance	337	316	670	603
Operating and maintenance from affiliate	47	39	92	78
Depreciation and amortization	177	174	352	347
Taxes other than income	69	72	146	149
Total operating expenses	905	870	1,861	1,766
Operating income	243	258	472	496
Other income and (deductions)				
Interest expense, net	(78)	(76)	(158)	(153)
Interest expense to affiliates	(3)	(4)	(7)	(7)
Other, net	5	5	9	10
Total other income and (deductions)	(76)	(75)	(156)	(150)
Income before income taxes	167	183	316	346
Income taxes	68	72	127	137
Net income	99	111	189	209
Comprehensive income	$ 99	$ 111	$ 189	$ 209

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Six Months Ended June 30, 2015	2014
Cash flows from operating activities		
Net income	$ 189	$ 209
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	352	347
Deferred income taxes and amortization of investment tax credits	36	63
Other non-cash operating activities	222	99
Changes in assets and liabilities:		
Accounts receivable	(57)	(83)
Receivables from and payables to affiliates, net	(10)	(46)
Inventories	(19)	(4)
Accounts payable, accrued expenses and other current liabilities	(52)	27
Income taxes	239	5
Pension and non-pension postretirement benefit contributions	(125)	(236)
Other assets and liabilities	25	48
Net cash flows provided by operating activities	800	429
Cash flows from investing activities		
Capital expenditures	(1,061)	(747)
Proceeds from sales of investments		7
Purchases of investments		(3)
Change in restricted cash		(2)
Other investing activities	17	14
Net cash flows used in investing activities	(1,044)	(731)
Cash flows from financing activities		
Changes in short-term borrowings	199	314
Issuance of long-term debt	400	650
Retirement of long-term debt	(260)	(617)
Contributions from parent	45	112
Dividends paid on common stock	(150)	(153)
Other financing activities	(5)	(2)
Net cash flows provided by financing activities	229	304
Increase (decrease) in cash and cash equivalents	(15)	2
Cash and cash equivalents at beginning of period	66	36
Cash and cash equivalents at end of period	$ 51	$ 38

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 51	$ 66
Restricted cash	4	4
Accounts receivable, net		
Customer	522	477
Other	569	648
Receivables from affiliates	14	14
Inventories, net	144	125
Regulatory assets	276	349
Other	36	40
Total current assets	1,616	1,723
Property, plant and equipment, net	16,493	15,793
Deferred debits and other assets		
Regulatory assets	834	852
Goodwill	2,625	2,625
Receivables from affiliates	2,538	2,571
Prepaid pension asset	1,572	1,551
Other	283	277
Total deferred debits and other assets	7,852	7,876
Total assets	$ 25,961	$ 25,392

See the Combined Notes to Consolidated Financial Statements

Table of Contents

COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 503	$ 304
Long-term debt due within one year		260
Accounts payable	580	598
Accrued expenses	291	331
Payables to affiliates	73	84
Customer deposits	128	128
Regulatory liabilities	154	125
Deferred income taxes	20	63
Mark-to-market derivative liability	20	20
Other	75	73
Total current liabilities	1,844	1,986
Long-term debt	6,099	5,698
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	4,579	4,498
Asset retirement obligations	103	103
Non-pension postretirement benefits obligations	262	263
Regulatory liabilities	3,622	3,655
Mark-to-market derivative liability	203	187
Other	1,049	889
Total deferred credits and other liabilities	9,818	9,595
Total liabilities	17,967	17,485
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	5,516	5,468
Retained earnings	890	851
Total shareholders equity	7,994	7,907
Total liabilities and shareholders equity	$ 25,961	$ 25,392

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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			189		189
Appropriation of retained earnings for future dividends			(189)	189	
Common stock dividends				(150)	(150)
Contribution from parent		45			45
Parent tax matter indemnification		3			3
Balance, June 30, 2015	$ 1,588	$ 5,516	$ (1,639)	$ 2,529	$ 7,994

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2015**	**2014**	**2015**	**2014**
Operating revenues				
Operating revenues	$ 661	$ 656	$ 1,645	$ 1,648
Operating revenues from affiliates			1	1
Total operating revenues	661	656	1,646	1,649
Operating expenses				
Purchased power and fuel	189	193	565	570
Purchased power from affiliate	48	48	110	135
Operating and maintenance	166	160	363	416
Operating and maintenance from affiliates	26	24	51	48
Depreciation and amortization	69	59	131	117
Taxes other than income	39	38	80	80
Total operating expenses	537	522	1,300	1,366
Gain on sale of assets			1	
Operating income	124	134	347	283
Other income and (deductions)				
Interest expense, net	(25)	(25)	(50)	(50)
Interest expense to affiliates	(3)	(3)	(6)	(6)
Other, net	1	1	3	3
Total other income and (deductions)	(27)	(27)	(53)	(53)
Income before income taxes	97	107	294	230
Income taxes	27	23	85	57
Net income attributable to common shareholder	70	84	209	173
Comprehensive income	$ 70	$ 84	$ 209	$ 173

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(In millions)	**2015**	**2014**
Cash flows from operating activities		
Net income	$ 209	$ 173
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	131	117
Deferred income taxes and amortization of investment tax credits	4	6
Other non-cash operating activities	45	50
Changes in assets and liabilities:		
Accounts receivable	(18)	34
Receivables from and payables to affiliates, net	(2)	(21)
Inventories	21	22
Accounts payable, accrued expenses and other current liabilities	3	30
Income taxes	57	54
Pension and non-pension postretirement benefit contributions	(15)	(11)
Other assets and liabilities	(60)	(114)
Net cash flows provided by operating activities	375	340
Cash flows from investing activities		
Capital expenditures	(289)	(308)
Change in restricted cash	(1)	
Other investing activities	9	6
Net cash flows used in investing activities	(281)	(302)
Cash flows from financing activities		
Change in Exelon intercompany money pool	41	
Dividends paid on common stock	(139)	(160)
Other financing activities		(2)
Net cash flows used in financing activities	(98)	(162)
Decrease in cash and cash equivalents	(4)	(124)
Cash and cash equivalents at beginning of period	30	217
Cash and cash equivalents at end of period	$ 26	$ 93

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 26	$ 30
Restricted cash and cash equivalents	3	2
Accounts receivable, net		
Customer	301	320
Other	122	141
Receivables from affiliates	3	3
Inventories, net		
Fossil fuel	30	57
Materials and supplies	28	22
Deferred income taxes	69	69
Prepaid utility taxes	80	10
Regulatory assets	42	29
Other	36	31
Total current assets	740	714
Property, plant and equipment, net	6,957	6,801
Deferred debits and other assets		
Regulatory assets	1,552	1,529
Investments	28	31
Receivable from affiliates	477	490
Prepaid pension asset	341	344
Other	31	34
Total deferred debits and other assets	2,429	2,428
Total assets	$ 10,126	$ 9,943

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 319	$ 337
Accrued expenses	116	91
Payables to affiliates	50	52
Borrowings from Exelon intercompany money pool	41	
Customer deposits	54	52
Regulatory liabilities	117	90
Other	41	31
Total current liabilities	738	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	2,724	2,671
Asset retirement obligations	30	29
Non-pension postretirement benefits obligations	287	287
Regulatory liabilities	633	657
Other	93	95
Total deferred credits and other liabilities	3,767	3,739
Total liabilities	6,935	6,822
Commitments and contingencies		
Shareholder s equity		
Common stock	2,439	2,439
Retained earnings	751	681
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,191	3,121
Total liabilities and shareholder s equity	$ 10,126	$ 9,943

See the Combined Notes to Consolidated Financial Statements

Table of Contents

PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholder s Equity
Balance, December 31, 2014	$ 2,439	$ 681	$ 1	$ 3,121
Net income		209		209
Common stock dividends		(139)		(139)
Balance, June 30, 2015	$ 2,439	$ 751	$ 1	$ 3,191

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2015**	**2014**	**2015**	**2014**
Operating revenue				
Operating revenue	$ 627	$ 651	$ 1,656	$ 1,689
Operating revenue from affiliates	1	2	8	18
Total operating revenues	628	653	1,664	1,707
Operating expenses				
Purchased power and fuel	143	183	493	592
Purchased power from affiliate	96	85	233	205
Operating and maintenance	120	163	276	326
Operating and maintenance from affiliates	29	25	55	50
Depreciation and amortization	87	89	192	197
Taxes other than income	54	53	111	113
Total operating expenses	529	598	1,360	1,483
Operating income	99	55	304	224
Other income and (deductions)				
Interest expense, net	(20)	(23)	(42)	(47)
Interest expense to affiliates	(4)	(4)	(8)	(8)
Other, net	4	5	8	9
Total other income and (deductions)	(20)	(22)	(42)	(46)
Income before income taxes	79	33	262	178
Income taxes	32	14	105	72
Net income	47	19	157	106
Preference stock dividends	3	3	6	6
Net income attributable to common shareholder	44	16	151	100
Comprehensive income	$ 47	$ 19	$ 157	$ 106

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(In millions)	**2015**	**2014**
Cash flows from operating activities		
Net income	$ 157	$ 106
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	192	197
Deferred income taxes and amortization of investment tax credits	54	47
Other non-cash operating activities	76	89
Changes in assets and liabilities:		
Accounts receivable	25	44
Receivables from and payables to affiliates, net	(2)	(12)
Inventories	23	
Accounts payable, accrued expenses and other current liabilities	(49)	(74)
Counterparty collateral (posted) received, net	(23)	27
Income taxes	(6)	(14)
Pension and non-pension postretirement benefit contributions	(9)	(8)
Other assets and liabilities	51	8
Net cash flows provided by operating activities	489	410
Cash flows from investing activities		
Capital expenditures	(304)	(313)
Change in restricted cash	21	(30)
Other investing activities	8	11
Net cash flows used in investing activities	(275)	(332)
Cash flows from financing activities		
Changes in short-term borrowings	(120)	(65)
Retirement of long-term debt	(37)	(35)
Dividends paid on preference stock	(6)	(6)
Dividends paid on common stock	(77)	
Other financing activities	(14)	12
Net cash flows used in financing activities	(254)	(94)
Decrease in cash and cash equivalents	(40)	(16)
Cash and cash equivalents at beginning of period	64	31
Cash and cash equivalents at end of period	$ 24	$ 15

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
ASSETS		
Current assets		
Cash and cash equivalents	$ 24	$ 64
Restricted cash and cash equivalents	29	50
Accounts receivable, net		
Customer	360	390
Other	76	82
Inventories, net		
Gas held in storage	29	57
Materials and supplies	35	30
Deferred income taxes	12	6
Prepaid utility taxes		59
Regulatory assets	207	214
Other	4	5
Total current assets	776	957
Property, plant and equipment, net	6,373	6,204
Deferred debits and other assets		
Regulatory assets	486	510
Investments	13	12
Prepaid pension asset	344	370
Other	25	25
Total deferred debits and other assets	868	917
Total assets[a]	$ 8,017	$ 8,078

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	June 30, 2015 (Unaudited)	December 31, 2014
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$	$ 120
Long-term debt due within one year	77	75
Accounts payable	194	215
Accrued expenses	108	131
Deferred income taxes	48	52
Payables to affiliates	52	66
Customer deposits	97	92
Regulatory liabilities	91	44
Other	33	51
Total current liabilities	700	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	1,930	1,865
Asset retirement obligations	18	17
Non-pension postretirement benefits obligations	209	212
Regulatory liabilities	185	200
Other	62	60
Total deferred credits and other liabilities	2,404	2,354
Total liabilities[(a)]	5,190	5,325
Commitments and contingencies		
Shareholders equity		
Common stock	1,360	1,360
Retained earnings	1,277	1,203
Total shareholders equity	2,637	2,563
Preference stock not subject to mandatory redemption	190	190
Total equity	2,827	2,753
Total liabilities and shareholders equity	$ 8,017	$ 8,078

(a) BGE s consolidated assets include $27 million and $24 million at June 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 $160 million and $197 million at June 30, 2015 and December 31, 2014, respectively, of BGE s consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

Table of Contents

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Total Shareholders Equity	Preference Stock Not Subject To Mandatory Redemption	Total Equity
Balance, December 31, 2014	$ 1,360	$ 1,203	$ 2,563	$ 190	$ 2,753
Net income		157	157		157
Preference stock dividends		(6)	(6)		(6)
Common stock dividends		(77)	(77)		(77)
Balance, June 30, 2015	$ 1,360	$ 1,277	$ 2,637	$ 190	$ 2,827

See the Combined Notes to Consolidated Financial Statements

Table of Contents

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.

The accompanying consolidated financial statements as of June 30, 2015 and 2014 and for the six 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,

34

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 standards are not yet required to be reflected in the combined financial statements of the Registrants.

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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The guidance is effective for the Registrants for fiscal years beginning after December 15, 2015. Early adoption is permitted. The guidance can be applied retrospectively to each prior reporting period presented or prospectively to arrangements entered into, or materially modified, after the effective date. The Registrants are currently assessing the impact this guidance may have on their financial positions, results of operations, cash flows and disclosures. 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.

Simplifying the Presentation of Debt Issuance Costs

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

Amendments to the Consolidation Analysis

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

Revenue from Contracts with Customers

In May 2014, the FASB issued authoritative guidance that changes the criteria for recognizing revenue from a contract with a customer. The new guidance replaces existing guidance on revenue recognition, including most industry specific guidance, with a five step model for recognizing and measuring revenue from contracts with customers. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability within industries, across industries and across capital markets. The underlying principle is that an entity will recognize revenue to depict the transfer of goods or services to customers at an amount that the entity expects to be entitled to in exchange for those goods or services. The guidance also requires a number of disclosures regarding the nature, amount, timing and uncertainty of revenue and the related cash flows. The guidance can be applied retrospectively to each prior reporting period presented (full retrospective method) or retrospectively with a cumulative effect adjustment to retained earnings for initial application of the guidance at the date of initial adoption (modified retrospective method). The Registrants are currently assessing the impacts this guidance may have on their financial positions, results of operations, cash flows and disclosures as well as the transition method that they will use to adopt the guidance. As currently issued, the guidance is effective for the Registrants for the first interim period within annual reporting periods beginning on or after December 15, 2016; and early adoption would not be permitted. However, in July 2015, the FASB approved 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. As of July 29, 2015, the amendment to defer the effective date and provide an option to early adopt had not been issued.

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 June 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 June 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

As of June 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 six months ended June 30, 2015, BGE remitted $21 million and $42 million to BondCo, respectively. During the three and six months ended June 30, 2014, BGE remitted $21 million and $42 million to BondCo, respectively.

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

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

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

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

under power purchase agreements with CENG, Generation will purchase 50.01% of the available output generated by the CENG nuclear plants 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 Reliability Support Services Agreement (RSSA) which Ginna entered into with Rochester Gas and Electric Corporation (RG&E) on February 13, 2015. The obligations under the RSSA commenced on April 1, 2015 and are effective through September 30, 2018 (see Note 5 Regulatory Matters for additional details),

Generation provided a $400 million loan to CENG. As of June 30, 2015, the remaining obligation is $288 million plus 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 June 30, 2015, the remaining obligation is approximately $2 million,

38

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 $8 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 June 30, 2015 and December 31, 2014 are as follows:

	June 30, 2015			December 31, 2014		
	Exelon[(a)]	Generation	BGE	Exelon[(a)]	Generation	BGE
Current assets	$ 924	$ 894	$ 24	$ 1,271	$ 1,242	$ 21

Noncurrent assets	7,731	7,723	3	7,580	7,566	3
Total assets	$ 8,655	$ 8,617	$ 27	$ 8,851	$ 8,808	$ 24
Current liabilities	$ 378	$ 292	$ 79	$ 611	$ 526	$ 77
Noncurrent liabilities	2,860	2,773	81	2,730	2,600	120
Total liabilities	$ 3,238	$ 3,065	$ 160	$ 3,341	$ 3,126	$ 197

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Assets and Liabilities of Consolidated VIEs

Included within the balances above are assets and liabilities of certain consolidated VIEs for which the assets can only be used to settle obligations of those VIEs, and liabilities that creditors, or beneficiaries, do not have recourse to the general credit of the Registrants. As of June 30, 2015 and December 31, 2014, these assets and liabilities primarily consisted of the following:

	June 30, 2015			December 31, 2014		
	Exelon	Generation	BGE	Exelon	Generation	BGE
Cash and cash equivalents	$ 240	$ 240	$	$ 392	$ 392	$
Restricted cash	145	121	24	117	96	21
Accounts receivable, net						
Customer	179	179		297	297	
Other	29	29		57	57	
Mark-to-market derivatives assets	96	96		171	171	
Inventory						
Materials and supplies	178	178		172	172	
Other current assets	32	25		33	26	
Total current assets	899	868	24	1,239	1,211	21
Property, plant and equipment, net	4,811	4,811		4,638	4,638	
Nuclear decommissioning trust funds	2,096	2,096		2,097	2,097	
Goodwill	47	47		47	47	
Mark-to-market derivatives assets	45	45		44	44	
Other noncurrent assets	91	82	3	95	82	3
Total noncurrent assets	7,090	7,081	3	6,921	6,908	3
Total assets	$ 7,989	$ 7,949	$ 27	$ 8,160	$ 8,119	$ 24
Long-term debt due within one year	$ 88	$ 5	$ 77	$ 87	$ 5	$ 75
Accounts payable	143	143		292	292	
Accrued expenses	87	84	1	111	108	2
Mark-to-market derivative liabilities	8	8		24	24	
Unamortized energy contract liabilities	9	9		22	22	
Other current liabilities	13	13		25	25	
Total current liabilities	348	262	78	561	476	77
Long-term debt	166	79	81	212	81	120
Asset retirement obligations	1,865	1,865		1,763	1,763	
Pension obligation[(a)]	9	9		9	9	
Unamortized energy contract liabilities	45	45		51	51	
Other noncurrent liabilities	122	122		127	127	
Noncurrent liabilities	2,207	2,120	81	2,162	2,031	120

Total liabilities	$ 2,555	$ 2,382	$ 159	$ 2,723	$ 2,507	$ 197

(a) Includes CNEG retail gas pension obligation, which is presented as a net asset balance within the Prepaid Pension asset line item on Generation s balance sheet. See Note 14 Retirement Benefits for additional details.

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include equity investments and energy purchase and sale contracts. For the equity investments, the carrying amount of the investments is

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 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 method investments and certain commercial agreements. The increase in the number of unconsolidated VIEs is due to the execution of an energy purchase and sale agreement with a new unconsolidated VIE.

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.

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

June 30, 2015	Commercial Agreement VIEs	Equity Investment VIEs	Total
Total assets[a]	$ 260	$ 127	$ 387
Total liabilities[a]	29	61	90
Exelon s ownership interest in VIE[a]		16	16
Other ownership interests in VIE[a]	231	51	282

Registrants maximum exposure to loss:			
Carrying amount of equity method investments		19	19
Contract intangible asset	9		9
Debt and payment guarantees		3	3
Net assets pledged for Zion Station decommissioning[(b)]	23		23

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 $264 million and $319 million as of June 30, 2015 and December 31, 2014, respectively; offset by payables to ZionSolutions, LLC of $241 million and $292 million as of June 30, 2015 and December 31, 2014, respectively. These items are included to provide information regarding the relative size of the ZionSolutions, LLC unconsolidated VIE.

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

4. Mergers, Acquisitions, and Dispositions (Exelon and Generation)

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

On April 29, 2014, Exelon and Pepco Holdings, Inc. (PHI) signed an agreement and plan of merger (as subsequently amended and restated as of July 18, 2014, the Merger Agreement) to combine the two companies in an all cash transaction. The resulting company will retain the Exelon name and be headquartered in Chicago. Under the Merger Agreement, PHI s shareholders will receive $27.25 of cash in exchange for each share of PHI common stock. In connection with the Merger Agreement, Exelon entered into a subscription agreement under which it has purchased $162 million of a new class of nonvoting, nonconvertible and nontransferable preferred securities of PHI as of June 30, 2015. The final investment of $18 million was paid on July 24, 2015 to reach the maximum aggregate investment of $180 million. The preferred securities are included in Other non-current assets on Exelon s Consolidated Balance Sheet. PHI has the right to redeem the preferred securities at its option for the purchase price paid plus accrued dividends, if any. Exelon expects total cash required to fund the acquisition of common stock and preferred securities plus other related acquisition costs to total approximately $7.2 billion.

On October 9, 2014, PHI and Exelon each received a request for additional information from the DOJ. The request had the effect of extending the DOJ review period until 30 days after PHI and Exelon each has certified that it had substantially complied with the request. On November 21, 2014, Exelon and PHI each certified that it had substantially complied with the request. Accordingly, the HSR Act waiting period expired on December 22,

42

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

2014, and the HSR Act no longer precludes completion of the merger. Although the DOJ allowed the waiting period under the HSR Act to expire without taking any action with respect to the merger, the DOJ has not advised Exelon or PHI that it has concluded its investigation. Exelon and PHI have cooperated with the DOJ regarding the proposed merger.

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (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 13, 2015, Exelon and PHI announced that they had reached a settlement agreement in the proceeding before the DPSC to review the proposed merger. The settlement, which was amended on April 7, 2015, was signed and filed by Exelon, PHI, Delmarva Power & Light Company (DPL), the DPSC Staff, the Delaware Public Advocate, the Delaware Department of Natural Resources and Environment Control, the Delaware Sustainable Energy Utility, the Mid-Atlantic Renewable Energy Coalition and the Clean Air Council. As part of this settlement, Exelon and PHI proposed a package of benefits to DPL customers and the state of Delaware including the establishment of customer rate credits of $40 million for DPL customers in Delaware, $2 million of funding for energy efficiency programs for DPL low income customers, and $2 million of funding for workforce development. On June 2, 2015, the DPSC issued an order accepting the settlement and approving the merger between Exelon and PHI.

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

On June 11, 2015, the Maryland Office of People s Counsel (OPC), the Sierra Club, and the Chesapeake Climate Action Network filed Petitions for Judicial Review of the MDPSC s approval of the merger with the Circuit Court for Queen Anne s County. On July 1, 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 responses 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. Exelon and PHI intend to vigorously oppose the motion.

The merger still requires approval by the public service commission of the District of Columbia. Exelon and PHI expect the merger to be completed in the third quarter of 2015.

Under the settlement terms and other conditions established in the merger approvals received to date and as proposed in the approval application in the District of Columbia, Exelon and PHI are required to expend in excess of $300 million, covering rate credits, funding for energy efficiency programs, sustainability funds, charitable contributions 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 2016.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The actual nature, amount, timing and financial reporting treatment for these commitments may be materially impacted by terms and conditions set forth in any final District of Columbia approval order. Further, the settlements reached and commission orders received to date include a most favored nation provision which, generally speaking, requires allocation of merger benefits proportionately across all the jurisdictions.

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 June 30, 2015, Exelon has incurred approximately $205 million of expense associated with the proposed merger. Of the total costs incurred, $89 million is primarily related to acquisition and integration costs and $116 million of 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 Merger Agreement also provides for termination rights for both parties. Under certain circumstances, if the Merger Agreement is terminated, PHI may be required to pay Exelon a termination fee ranging from $259 million to $293 million plus certain expenses. If the Merger Agreement is terminated due to a regulatory failure, Exelon may be required to pay PHI a termination fee equal to the amount of purchased nonvoting preferred securities of PHI described above, through the redemption by PHI of the outstanding nonvoting preferred securities for no consideration other than the nominal par value of the stock, plus certain expenses.

Merger Financing

Exelon intends to fund the all-cash transaction using a combination of debt, cash from asset sales primarily at Generation, and through issuance of equity (including mandatory convertible securities). On June 11, 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share in connection with forward sales agreements and $1.2 billion of junior subordinated notes in the form of 23 million equity units. In addition, Exelon signed a 364-day $7.2 billion senior unsecured bridge credit facility to support the contemplated transaction and provide flexibility for timing of permanent financing. In June 2015, Exelon issued $4.2 billion of long-term debt which resulted in the termination of the remaining $3.2 billion bridge facility. Additionally, in July 2015, Exelon elected to settle the forward sales agreements resulting in net proceeds of approximately $1.87 billion. See Note 11 Debt and Credit Agreements and Note 17 Common Stock for more information.

Asset Divestitures (Exelon and Generation)

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Regulatory and Legislative Proceedings (Exelon, Generation, ComEd, PECO and BGE)

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

Illinois Regulatory Matters

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

Participating utilities are required to file an annual update to the performance-based formula rate tariff on or before May 1, with resulting rates effective in January of the following year. This annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement(s) in effect for the prior year and actual costs incurred for that year. Throughout each year, ComEd records regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement(s) in effect and ComEd s best estimate of the revenue requirement expected to be approved by the ICC for that year s reconciliation. As of June 30, 2015, and December 31, 2014, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $275 million and $371 million, respectively. The regulatory asset associated with distribution true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

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

Participating utilities are also required to file an annual update on their AMI implementation progress. On June 11, 2014, the ICC approved ComEd s accelerated deployment plan which allows for the installation of more than 4 million smart meters throughout ComEd s service territory by 2018, three years in advance of the originally scheduled 2021 completion date. On April 1, 2015, ComEd filed an annual progress report on its AMI Implementation Plan with the ICC. To date, over 1.2 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. 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 would reflect a 4.4% increase on the basis of total Pennsylvania jurisdictional operating revenue. The requested rate of return on common equity is 10.95%. The new electric delivery rates would take effect no later than January 1, 2016. The results of the rate case are expected to be known in the fourth quarter of 2015. PECO cannot predict how much of the requested increase the PAPUC will ultimately approve.

Pennsylvania Procurement Proceedings (Exelon and PECO). On October 12, 2012, the PAPUC issued its Opinion and Order approving PECO s second DSP Program, which was filed with the PAPUC in January 2012. The program, which 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

commercial classes and spot market price full requirement contracts for the large commercial and industrial class load. In March 2015, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential class and its small, medium, and large commercial classes which commenced in June 2015. Charges incurred for electric supply procured through contracts with Generation are included in purchased power from affiliates on PECO s Statement of Operations and Comprehensive Income.

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design 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 June 30, 2015, PECO has spent $574 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 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. If approved, the DSIC will allow PECO the opportunity to recover the costs, subject to certain criteria, incurred to repair, improve or replace its electric distribution property between rate cases.

Maryland Regulatory Matters

2013 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On May 17, 2013, and as amended on August 23, 2013, BGE filed for electric and gas base increases with the MDPSC, ultimately

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015 and December 31, 2014, BGE recorded a regulatory asset of $160 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 cost estimates to be included in the 2015 surcharge. 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 June 30, 2015, BGE recorded a regulatory liability of $1 million, representing the difference between the surcharge revenues and program costs.

In February 2014, the residential consumer advocate in Maryland filed an appeal with the Baltimore City Circuit Court to the decision issued by the MDPSC on BGE s infrastructure replacement plan. On September 5, 2014, the Baltimore City Circuit Court affirmed the MDPSC decision on BGE s infrastructure replacement plan and associated surcharge. On October 10, 2014, the residential consumer advocate noticed its appeal to the Maryland Court of Special Appeals from the judgment entered by the Baltimore City Circuit Court. The Court of Special Appeals (the Court) has issued a preliminary procedural schedule that sets oral argument in this matter for a date in the first two weeks of November 2015. On July 24, 2015, the residential consumer advocate s brief was filed. BGE s brief is due by August 24, 2015, and the residential consumer advocate s reply brief by September 15, 2015.

New York Regulatory Matters

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). Ginna Nuclear Power Plant s (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the agreement, Ginna advised the New York Public Service Commission (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. RG&E may terminate the RSSA contract upon providing 12-months notice, which would require RG&E to make a specified termination payment to Ginna. The proposed RSSA contract extends through September 30, 2018. In the event that Ginna continues to operate beyond the RSSA term, Ginna would be required to make a specified refund payment to RG&E. The FERC issued an order on April 14, 2015, directing Ginna to make a compliance filing to ensure that the RSSA does not allow Ginna to receive revenues above its full cost-of-service and rejecting any extension of the RSSA beyond its initial term, rather requiring any extension be subject to the rules currently being developed by ISO-NY. The FERC order also set the RSSA for hearing and settlement procedures. 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. While the FERC order supports Ginna s current agreement, it remains subject to FERC hearing and settlement procedures. These procedures may result in modifications to the agreement, however, Ginna is unable to predict the ultimate outcome of these proceedings. The effectiveness of the RSSA or any settlement among the parties at FERC remains contingent on approval by the NYPSC of RG&E s full and timely recovery of rates associated with the costs incurred under the RSSA.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Until final regulatory approvals are received, Generation will recognize revenue based on market prices for energy and capacity delivered by Ginna into ISO-NY. Upon receiving regulatory approvals, under the RSSA contract terms, Generation would record an adjustment to recognize revenue based on the final approved pricing contained in the contract as of the April 1, 2015 effective date. While the RSSA is expected to receive regulatory approvals and, therefore, permit Ginna to continue operating through the RSSA term, there is still a risk that, for economic reasons, including adjustments to the revenue Ginna would be entitled to under the RSSA, Ginna could be retired before the end of its operating license period. In absence of such an agreement and in the event the plant is retired before the current license term ends in 2029, Exelon s and Generation s results of operations could be adversely affected by increased depreciation rates, impairment charges, severance costs, and accelerated future decommissioning costs, among other items. However, it is not expected that such impacts would be material to Exelon s or Generation s results of operations.

Federal Regulatory Matters

Transmission Formula Rate (Exelon, ComEd and BGE). ComEd s and BGE s transmission rates are each established based on a FERC-approved formula. ComEd and BGE are required to file an annual update to the FERC-approved formula on or before May 15, with the resulting rates effective on June 1 of the same year. The annual formula rate update is based on prior year actual costs and current year projected capital additions. The update also reconciles any differences between the revenue requirement in effect beginning June 1 of the prior year and actual costs incurred for that year. ComEd and BGE record regulatory assets or regulatory liabilities and corresponding increases or decreases to operating revenues for any differences between the revenue requirement in effect and ComEd s and BGE s best estimate of the revenue requirement expected to be approved by the FERC for that year s reconciliation. As of June 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. BGE recorded a net regulatory asset associated with the transmission formula rate of $1 million as of June 30, 2015 and December 31, 2014 each. 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 return on common equity 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 the FERC and 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 return on common equity 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 return on common equity (ROE) and a 50 basis point incentive for participating in PJM (the latter of which is conditioned upon crediting the first 50 basis points of any incentive ROE adders). The parties seek a reduction in the base return on equity to 8.7% and changes to the formula rate process. FERC docketed the matter and set April 3, 2013 as the deadline for interventions, protests and answers. Under FERC rules, the revenues subject to refund are limited to a fifteen month period and the earliest date from which the base ROE could be adjusted and refunds required is the date of the complaint. On March 19, 2013, BGE filed a motion to dismiss or sever the complaint.

On August 21, 2014, FERC issued an order in the BGE and PHI companies proceeding, which established hearing and settlement judge procedures for the complaint, and set a refund effective date of February 27, 2013. BGE, the PHI companies and the parties began settlement discussions under the guidance of a FERC administrative law judge on September 23, 2014. On November 24, 2014, the Settlement Judge informed FERC and the Chief Judge that the parties had reached an impasse and determined that a settlement was not possible. On November 26, 2014, the Chief Judge issued an order terminating the settlement proceeding, designating a presiding judge at the hearings and directing that an initial decision be issued by November 25, 2015.

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

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

PJM Transmission Rate Design and Operating Agreements (Exelon, ComEd, PECO and BGE). PJM Transmission Rate Design specifies the rates for transmission service charged to customers within PJM. Currently, ComEd, PECO and BGE incur costs based on the existing rate design, which charges customers based on the cost of the existing transmission facilities within their load zone and the cost of new transmission facilities based on those who benefit from those facilities. In April 2007, FERC issued an order concluding that PJM s current rate design for existing facilities is just and reasonable and should not be changed. In the same order, FERC held that the costs of new facilities 500 kV and above should be socialized across the entire PJM footprint and that the costs of new facilities less than 500 kV should be allocated to the customers of the new facilities who caused the need for those facilities. A number of parties appealed to the U.S. Court of Appeals for the Seventh Circuit.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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 June 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. The FERC and several other parties sought rehearing of the D.C. Circuit Decision, which was denied in September 2014. In addition, on September 22, 2014, the FERC and another party sought to stay the issuance of the D.C. Circuit Court s mandate so that the FERC may appeal the decision to the U.S. Supreme Court. The stay was granted with respect to the FERC s request only. In January 2015, the FERC sought to appeal the decision to the U.S. Supreme Court. The U.S. Supreme Court agreed to consider the appeal. In addition, contemporaneously with the D.C. Circuit Court s decision on May 23, 2014, First Energy filed a complaint at the FERC asking the FERC to direct PJM to remove all PJM Tariff provisions that allow or require PJM to compensate demand response providers as a form of supply in the PJM capacity market effective May 23, 2014. FirstEnergy also asked the FERC to declare the results of PJM s May 2014 Base Residual Auction for the 2017/2018 Delivery Year, void and illegal to the extent that demand response resources cleared that auction. On November 14, 2014, the New England Power Generators Association, Inc. (NEPGA) filed a similar complaint at the FERC asking the FERC to disqualify demand response from the upcoming capacity auction in New England and to revise the New England tariff to remove demand response from participation in the capacity market. The FERC s response to the FirstEnergy complaint and the NEPGA complaint and its response to address the D.C. Circuit Court s decision in all markets could preclude demand response resources from receiving any future capacity market revenues and also subject such resources to refund obligations depending on how the U.S. Supreme Court resolves the matter. In addition, there is uncertainty as to how the FERC might treat already settled capacity market auctions as well as future auctions, both for demand response resources and generation resources, again depending on the U.S. Supreme Court resolution. Due to these uncertainties, the Registrants are unable to predict the outcome of these proceedings, and the final outcome is not expected for several months. Nonetheless, the final decision and its implementation by FERC and the RTOs and ISOs, could be material to Exelon, Generation, ComEd, PECO and BGE s results of operations and cash flows.

New England Capacity Market Results (Exelon and Generation). Each year, ISO New England, Inc. (ISO-NE) files the results of its annual capacity auction at the FERC which is required to include documentation regarding the competitiveness of the auction. Consistent with this requirement, on February 27, 2015, ISO-NE filed the results of its ninth capacity auction (covering the June 1, 2018 through May 30, 2019 delivery period). On June 18, 2015, the FERC accepted the results of the ninth capacity auction.

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

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

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

On June 3, 2014, and subsequently modified December 9, 2014, the PA DEP issued its water quality certificate for Muddy Run, which is a necessary step in the FERC licensing process and included certain commitments made by Generation. On March 2, 2015, Generation and US Fish and Wildlife Services (USFWS) submitted to FERC an executed settlement agreement resolving all outstanding issues related to Muddy Run. The

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015, $42 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 June 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.

June 30, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**
Regulatory assets				
Pension and other postretirement benefits	$ 3,193	$	$	$
Deferred income taxes	1,574	65	1,432	77
AMI programs	349	119	70	160
Under-recovered distribution service costs[a]	275	275		
Debt costs	51	49	2	8
Fair value of BGE long-term debt	177			
Severance	11			11
Asset retirement obligations	121	76	26	19
MGP remediation costs	245	210	34	1
Under-recovered uncollectible accounts	50	50		
Renewable energy	223	223		
Energy and transmission programs[b] [c]	53	34		19
Deferred storm costs	2			2
Electric generation-related regulatory asset	25			25
Rate stabilization deferral	121			121
Energy efficiency and demand response programs	236			236
Merger integration costs	7			7
Conservation voltage reduction	2			2
Other	46	9	30	5
Total regulatory assets	6,761	1,110	1,594	693

Less: current portion	785	276	42	207
Total noncurrent regulatory assets	$ 5,976	$ 834	$ 1,552	$ 486

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

June 30, 2015	Exelon	ComEd	PECO	BGE
Regulatory liabilities				
Other postretirement benefits	$ 68	$	$	$
Nuclear decommissioning	2,831	2,354	477	
Removal costs	1,563	1,351		212
Energy efficiency and demand response programs	41	39	2	
DLC Program Costs	9		9	
Energy efficiency phase II	38		38	
Electric distribution tax repairs	102		102	
Gas distribution tax repairs	33		33	
Energy and transmission programs[b][c][d]	134	30	85	19
Over-recovered electric universal service fund costs	2		2	
Over-recovered revenue decoupling[e]	40			40
Other	10	2	2	5
Total regulatory liabilities	4,871	3,776	750	276
Less: current portion	409	154	117	91
Total noncurrent regulatory liabilities	$ 4,462	$ 3,622	$ 633	$ 185

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	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	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)(d)	84	19	58	7
Over-recovered electric universal service fund costs	2		2	
Revenue subject to refund	3	3		
Over-recovered revenue decoupling(e)	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 June 30, 2015, ComEd s regulatory asset of $275 million was comprised of $209 million for the applicable annual reconciliations and $66 million related to significant one-time events including $51 million of deferred storm costs and $15 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 June 30, 2015, ComEd s regulatory asset of $34 million included $1 million related to under-recovered energy costs for non-hourly customers, $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 June 30, 2015, ComEd s regulatory liability of $30 million included $10 million related to over-recovered energy costs for hourly customers and $20 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 June 30, 2015, BGE s regulatory asset of $19 million included $1 million associated with transmission costs recoverable through its FERC approved formula rate and $18 million related to under-recovered electric energy costs. As of June 30, 2015, BGE s regulatory liability of $19 million related to $18 million of over-recovered natural gas supply costs and $6 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) As of June 30, 2015, PECO s regulatory liability of $85 million included $35 million related to the DSP program, $44 million related to the over-recovered natural gas costs under the PGC, $5 million related to over-recovered electric transmission costs and $1 million related to the Non-Bypassable service charge included in the DSP program. 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(e) Represents the electric and gas distribution costs recoverable from customers under BGE s decoupling mechanism. As of June 30, 2015, BGE had a regulatory liability of $11 million related to over-recovered electric revenue decoupling and a regulatory liability of $29 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.

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 June 30, 2015 and December 31, 2014.

As of June 30, 2015	**Exelon**	**ComEd**	**PECO**	**BGE**
Purchased receivables[(a)]	$ 275	$ 128	$ 80	$ 67
Allowance for uncollectible accounts[(b)]	(40)	(22)	(8)	(10)
Purchased receivables, net	$ 235	$ 106	$ 72	$ 57

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. If the costs are not fully recovered when PECO files its next gas distribution rate case, PECO will propose a mechanism to recover the remaining implementation costs as a distribution charge to low volume transportation customers or apply future discounts on purchased receivables from natural gas suppliers serving those customers.

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

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

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

As a result of the consolidation of CENG on April 1, 2014, there are several additional transactions included in Exelon s and Generation s consolidated financial statements between CENG and Exelon s affiliates that are considered related party transactions to Generation. As further described in Note 25 Related Party Transactions of the Exelon 2014 Form 10-K, EDF and Generation had a PPA with CENG under which they purchased 15% and 85%, respectively, of the nuclear output owned by CENG that was not sold to third parties under pre-existing PPAs through December 31, 2014. Beginning January 1, 2015 and continuing through the life of the respective plants, EDF and Generation will purchase 49.99% and 50.01%, respectively, of the nuclear output owned by CENG not subject to other contractual agreements. Beginning April 1, 2014, CENG s sales to Generation have been eliminated in consolidation. For the three and six months ended June 30, 2015, Generation had sales to EDF of $106 million and $288 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 Registrants 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 six months ended June 30, 2015, Generation reduced by $4 million and $9 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 $109 million and $306 million and CENG s net (loss) income, prior to any intercompany eliminations and any adjustments for noncontrolling interest, of $(4) million and $93 million during the three and six months ended June 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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

Like-Kind Exchange Transaction (Exelon)

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

	June 30, 2015	December 31, 2014
Estimated residual value of leased assets	$ 639	$ 685
Less: unearned income	295	324
Net investment in long-term leases	$ 344	$ 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 the PJM capacity auction for the 2018/2019 delivery year, the effects of the new PJM Capacity Performance product, 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 outcome of the Ginna RSSA hearing and settlement procedures and the resulting contractual terms and conditions. Exelon and Generation have not made any decisions regarding potential plant closures at this time; however, various upcoming milestones could influence the timing of any such decisions, which could occur as soon as the third quarter of 2015. In September 2015, Generation has an obligation to inform PJM if any of its plants in the PJM region will not be participating in the May 2016 PJM capacity auction for delivery year beginning June 1, 2019. In December 2015, Generation must inform MISO if the Clinton plant will not be in operation during the next MISO resource adequacy planning year that begins June 1, 2016.

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 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: 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, among other items. 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 June 30, 2015 for significant assets and liabilities associated with the three nuclear plants currently deemed 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	$ 48	$ 55	$ 30	$ 133
Nuclear fuel inventory	205	137	66	408
Completed plant, net	800	465	85	1,350
Construction work in progress	24	24	23	71
Liability Balances				
Asset retirement obligation	(450)	(287)	(611)	(1,348)
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 was 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 June 30, 2015 and December 31, 2014:

Exelon

	June 30, 2015				
	Carrying	Fair Value			
	Amount	Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 546	$ 3	$ 543	$	$ 546
Long-term debt (including amounts due within one year)	25,446	1,043	24,011	1,349	26,403
Long-term debt to financing trusts	648			663	663
SNF obligation	1,021		838		838

61

Table of Contents

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

	June 30, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 40	$	$ 40	$	$ 40
Long-term debt (including amounts due within one year)	9,001		7,995	1,349	9,344
SNF obligation	1,021		838		838

	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

	June 30, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 503	$	$ 503	$	$ 503
Long-term debt (including amounts due within one year)	6,099		6,640		6,640
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

June 30, 2015

Fair Value

	Carrying Amount	Level 1	Level 2	Level 3	Total
Long-term debt (including amounts due within one year)	$ 2,246	$	$ 2,432	$	$ 2,432
Long-term debt to financing trusts	184			199	199

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

BGE

	June 30, 2015				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 3	$ 3	$	$	$ 3
Long-term debt (including amounts due within one year)	1,905		2,086		2,086
Long-term debt to financing trusts	258			258	258

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

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

Long-Term Debt. The fair value amounts of Exelon s taxable debt securities (Level 2) are determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk of the Registrants into the discount rates, Exelon obtains pricing (i.e., U.S. Treasury rate plus credit spread) based on trades of existing Exelon debt securities as well as debt securities of other issuers in the electric utility sector with similar credit ratings in both the primary and secondary market, across the Registrants debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note. The fair value of Exelon s equity units (Level 1) are valued based on publicly traded securities issued by Exelon.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 six months ended June 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 June 30, 2015 and December 31, 2014:

	Generation				Exelon			
As of June 30, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[a]	$ 134	$	$	$ 134	$ 5,486	$	$	$ 5,486
Nuclear decommissioning trust fund investments								
Cash equivalents	333	55		388	333	55		388
Equity								
Domestic	2,389	2,055		4,444	2,389	2,055		4,444
Foreign	696			696	696			696
Equity funds subtotal	3,085	2,055		5,140	3,085	2,055		5,140
Fixed income								
Corporate debt		1,860	250	2,110		1,860	250	2,110
U.S. Treasury and agencies	1,165			1,165	1,165			1,165
Foreign governments		83		83		83		83
State and municipal debt		405		405		405		405
Other		463		463		463		463
Fixed income subtotal	1,165	2,811	250	4,226	1,165	2,811	250	4,226
Middle market lending			417	417			417	417
Private Equity			100	100			100	100
Real Estate			19	19			19	19
Other		329		329		329		329
Nuclear decommissioning trust fund investments subtotal[b]	4,583	5,250	786	10,619	4,583	5,250	786	10,619
Pledged assets for Zion Station decommissioning								
Cash equivalents		17		17		17		17
Equities	5	1		6	5	1		6
Fixed income								
U.S. Treasury and agencies	7	2		9	7	2		9
Corporate debt		62		62		62		62
State and municipal debt		10		10		10		10
Other		3		3		3		3
Fixed income subtotal	7	77		84	7	77		84
Middle market lending			156	156			156	156
Pledged assets for Zion Station decommissioning subtotal[c]	12	95	156	263	12	95	156	263
Rabbi trust investments in mutual funds[d][e]	17			17	48			48
Commodity derivative assets								

Economic hedges	1,080	3,352	2,334	6,766	1,080	3,352	2,334	6,766
Proprietary trading	117	239	38	394	117	239	38	394
Effect of netting and allocation of collateral[(f)]	(1,364)	(2,753)	(872)	(4,989)	(1,364)	(2,753)	(872)	(4,989)
Commodity derivative assets subtotal	(167)	838	1,500	2,171	(167)	838	1,500	2,171
Interest rate and foreign currency derivative assets								
Derivatives designated as hedging instruments		1		1		22		22
Economic hedges		20		20		20		20
Proprietary trading	14	1		15	14	1		15
Effect of netting and allocation of collateral	(8)	(5)		(13)	(8)	(5)		(13)
Interest rate and foreign currency derivative assets subtotal	6	17		23	6	38		44
Other investments			30	30	1		30	31
Total assets	4,585	6,200	2,472	13,257	9,969	6,221	2,472	18,662

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation				Exelon			
As of June 30, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Liabilities								
Commodity derivative liabilities								
Economic hedges	(1,493)	(3,129)	(1,462)	(6,084)	(1,493)	(3,129)	(1,685)	(6,307)
Proprietary trading	(111)	(248)	(43)	(402)	(111)	(248)	(43)	(402)
Effect of netting and allocation of collateral[f]	1,641	3,296	1,026	5,963	1,641	3,296	1,026	5,963
Commodity derivative liabilities subtotal	37	(81)	(479)	(523)	37	(81)	(702)	(746)
Interest rate and foreign currency derivative liabilities								
Derivatives designated as hedging instruments		(14)		(14)		(14)		(14)
Economic hedges		(4)		(4)		(4)		(4)
Proprietary trading	(14)			(14)	(14)			(14)
Effect of netting and allocation of collateral	14	5		19	14	5		19
Interest rate and foreign currency derivative liabilities subtotal		(13)		(13)		(13)		(13)
Deferred compensation obligation		(26)		(26)		(88)		(88)
Total liabilities	37	(120)	(479)	(562)	37	(182)	(702)	(847)
Total net assets	$ 4,622	$ 6,080	$ 1,993	$ 12,695	$ 10,006	$ 6,039	$ 1,770	$ 17,815

	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
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

66

Table of Contents

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**
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 $(12) million and $(5) million at June 30, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $1 million and $3 million at June 30, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $36 million and $35 million of cash surrender value of life insurance investment at June 30, 2015 and December 31, 2014, respectively, at Exelon Consolidated. Excludes $13 million and $11 million and of cash surrender value of life insurance investment at June 30, 2015 and December 31, 2014, respectively, at Generation.

(e) The mutual funds held by the Rabbi trusts at Exelon include $47 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at June 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 $277 million, $543 million and $154 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of June 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 mark-to-market derivatives, respectively, as of December 31, 2014.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd, PECO and BGE

The following tables present assets and liabilities measured and recorded at fair value on the utility Registrants Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of June 30, 2015 and December 31, 2014:

	ComEd				PECO				BGE			
As of June 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	$ 5	$	$	$ 5	$ 5	$	$	$ 5	$ 46	$	$	$ 46
Rabbi trust investments in mutual funds[(a)]					8			8	5			5
Total assets	5			5	13			13	51			51
Liabilities												
Deferred compensation obligation		(7)		(7)		(10)		(10)		(3)		(3)
Mark-to-market derivative liabilities[(b)]			(223)	(223)								
Total liabilities		(7)	(223)	(230)		(10)		(10)		(3)		(3)
Total net assets (liabilities)	$ 5	$ (7)	$ (223)	$ (225)	$ 13	$ (10)	$	$ 3	$ 51	$ (3)	$	$ 48

	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 June 30, 2015 and December 31, 2014, respectively.

(b) The Level 3 balance includes the current and noncurrent liability of $20 million and $203 million at June 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 30, 2015 and 2014:

	Generation					ComEd		Exelon
Three Months Ended June 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 March 31, 2015	$ 715	$ 178	$ 1,066	$ 3	$ 1,962	$ (241)	$	$ 1,721
Total realized / unrealized gains (losses)								
Included in net income	2		(7)[a]		(5)			(5)
Included in noncurrent payables to affiliates	7				7		(7)	
Included in payable for Zion Station decommissioning		(2)			(2)			(2)
Included in regulatory assets						18	7	25
Change in collateral			(30)		(30)			(30)
Purchases, sales, issuances and settlements								
Purchases	99	6	16	27	148			148
Sales		(26)	(5)		(31)			(31)
Settlements	(37)				(37)			(37)
Transfers into Level 3			11		11			11
Transfers out of Level 3			(30)		(30)			(30)
Balance as of June 30, 2015	$ 786	$ 156	$ 1,021	$ 30	$ 1,993	$ (223)	$	$ 1,770
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 June 30, 2015	$ 4	$	$ 175	$	$ 179	$	$	$ 179

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2015	Generation: Nuclear Decommissioning Trust Fund Investments	Generation: Pledged Assets for Zion Station Decommissioning	Generation: Mark-to-Market Derivatives	Generation: Other Investments	Generation: Total Generation	ComEd: Mark-to-Market Derivatives[b]	Eliminated in Consolidation	Exelon: Total
Balance as of December 31, 2014	$ 691	$ 184	$ 1,050	$ 3	$ 1,928	$ (207)	$	$ 1,721
Total realized / unrealized gains (losses)								
Included in net income	4		(39)[a]		(35)			(35)
Included in noncurrent payables to affiliates	15				15		(15)	
Included in payable for Zion Station decommissioning		1			1			1
Included in regulatory assets						(16)	15	(1)
Change in collateral			(18)		(18)			(18)
Purchases, sales, issuances and settlements								
Purchases	146	11	57	27	241			241
Sales	(8)	(40)	(5)		(53)			(53)
Settlements	(66)				(66)			(66)
Transfers into Level 3	4		11		15			15
Transfers out of Level 3			(35)		(35)			(35)
Balance as of June 30, 2015	$ 786	$ 156	$ 1,021	$ 30	$ 1,993	$ (223)	$	$ 1,770
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 six months ended June 30, 2015	$ 5	$	$ 355	$	$ 360	$	$	$ 360

(a) Includes the reclassification of $(182) million and $(394) million of realized losses due to the settlement of derivative contracts for the three and six months ended June 30, 2015, respectively.

(b) Includes $14 million of increases in fair value and realized losses due to settlements of $4 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2015. Includes $22 million of decreases in fair value and realized losses due to settlements of $6 million for the six months ended June 30, 2015.

70

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					ComEd		Exelon
Three Months Ended June 30, 2014	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[b]**	**Eliminated in Consolidation**	**Total**
Balance as of March 31, 2014	$ 486	$ 137	$ 287	$ 10	$ 920	$ (168)	$	$ 752
Total realized / unrealized gains (losses)								
Included in net income	2		(48)[a]		(46)			(46)
Included in noncurrent payables to affiliates	8				8		(8)	
Included in payable for Zion Station decommissioning		4			4			4
Included in regulatory assets						34	8	42
Change in collateral			34		34			34
Purchases, sales, issuances and settlements								
Purchases	109	13	5		127			127
Sales	(1)	(21)	(4)		(26)			(26)
Settlements	(12)				(12)			(12)
Transfers into Level 3			(4)		(4)			(4)
Transfers out of Level 3			(28)		(28)			(28)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977	$ (134)	$	$ 843
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 June 30, 2014	$ 2	$	$ 19	$	$ 21	$	$	$ 21

71

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation					ComEd		Exelon
Six Months Ended June 30, 2014	**Nuclear Decommissioning Trust Fund Investments**	**Pledged Assets for Zion Station Decommissioning**	**Mark-to-Market Derivatives**	**Other Investments**	**Total Generation**	**Mark-to-Market Derivatives[b]**	**Eliminated in Consolidation**	**Total**
Balance as of December 31, 2013	$ 350	$ 112	$ 465	$ 15	$ 942	$ (193)	$	$ 749
Total realized / unrealized gains (losses)								
Included in net income	3		(360)[a]		(357)			(357)
Included in noncurrent payables to affiliates	11				11		(11)	
Included in payable for Zion Station decommissioning		4			4			4
Included in regulatory assets						59	11	70
Change in collateral			178		178			178
Purchases, sales, issuances and settlements								
Purchases	249	42	15	2	308			308
Sales	(2)	(25)	(6)		(33)			(33)
Settlements	(19)				(19)			(19)
Transfers into Level 3			(30)		(30)			(30)
Transfers out of Level 3			(20)	(7)	(27)			(27)
Balance as of June 30, 2014	$ 592	$ 133	$ 242	$ 10	$ 977	$ (134)	$	$ 843
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the six months ended June 30, 2014	$ 2	$	$ (427)	$	$ (425)	$	$	$ (425)

(a) Includes the reclassification of $67 million of realized losses due to the settlement of derivative contracts for the three and six months ended June 30, 2014.

(b) Includes $34 million of increases in fair value and immaterial realized losses recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended June 30, 2014. Includes $64 million of increases in fair value and realized gains due to settlements of $5 million for the six months ended June 30, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three and six months ended June 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 June 30, 2015	$ (17)	$ 10	$ 2	$ (17)	$ 10	$ 2
Total gains (losses) included in net income for the six months ended June 30, 2015	(27)	(12)	4	(27)	(12)	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2015	171	4	4	171	4	4
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2015	340	15	5	340	15	5

	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 June 30, 2014	$ (62)	$ 14	$ 2	$ (62)	$ 14	$ 2
Total gains (losses) included in net income for the six months ended June 30, 2014	(330)	(30)	3	(330)	(30)	3
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended June 30, 2014	(10)	29	2	(10)	29	2
Change in the unrealized gains (losses) relating to assets and liabilities held for the six months ended June 30, 2014	(435)	8	2	(435)	8	2

(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 models including cost models, market models, and income models. Investments in middle market lending are

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015, Generation has outstanding commitments to invest in middle market lending, corporate debt securities, private equity investments, and real estate investments of approximately $312 million. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

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

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon s executive management and directors. The Rabbi trusts assets are included in investments in the Registrants Consolidated Balance Sheets and consist primarily of mutual funds and life insurance policies. The mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon s overall investment strategy. Mutual funds are publicly quoted and have been categorized as Level 1 given the clear observability of the prices. The life insurance policies are valued using the cash surrender value of the policies, which is provided by a third party. The cash surrender value inputs are not observable.

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

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

discounted by the market s expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 10 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

Deferred Compensation Obligations (Exelon, Generation, ComEd, PECO and BGE). The Registrants deferred compensation plans allow participants to defer certain cash compensation into a notional investment account. The Registrants include such plans in other current and noncurrent liabilities in their Consolidated Balance Sheets. The value of the Registrants deferred compensation obligations is based on the market value of the participants notional investment accounts. The underlying notional investments are comprised primarily of equities, mutual funds, commingled funds, and fixed income securities which are based on directly and indirectly observable market prices. Since the deferred compensation obligations themselves are not exchanged in an active market, they are categorized as Level 2 in the fair value hierarchy.

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

Mark-to-Market Derivatives (Exelon, Generation, ComEd). For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations whose contract tenure extends into unobservable periods. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 as the model inputs generally are not observable. Exelon s RMC approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The RMC is chaired by the chief executive officer and includes the chief risk officer, chief strategy officer, chief executive officer of Exelon Utilities, chief commercial officer, chief financial officer and chief executive officer of Constellation. The RMC reports to the Finance and Risk Committee of the Exelon Board of Directors on the scope of the risk management activities. Forward price curves for the power market utilized by the front office to manage the portfolio, are reviewed and verified by the middle office, and used for financial reporting by the back office. The Registrants consider credit and nonperformance risk in the valuation of derivative contracts categorized in Level 2 and 3, including both historical and current market data in its assessment of credit and nonperformance risk by counterparty. Due to master netting agreements and collateral posting requirements, the impacts of credit and nonperformance risk were not material to the financial statements.

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

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 $3.33 and $0.34 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 June 30, 2015	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic hedges (Generation)(a)(c)	$ 872	Discounted Cash Flow	Forward power price	$11 - $122(d)
			Forward gas price	$1.27 - $13.46(d)
		Option Model	Volatility percentage	8% - 233%
Mark-to-market derivatives Proprietary trading (Generation)(a)(c)	$ (5)	Discounted Cash Flow	Forward power price	$13 - $119(d)
Mark-to-market derivatives (ComEd)	$ (223)	Discounted Cash Flow	Forward heat rate(b)	9x - 10x
			Marketability reserve	3.5% - 7%
			Renewable factor	86% - 123%

(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(c) The fair values do not include cash collateral held on level three positions of $154 million as of June 30, 2015.
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas economic hedges would be approximately $108 and $8.53, respectively, and would be approximately $104 for power proprietary trading.

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 held on level three positions of $172 million as of December 31, 2014.
(d) The upper ends of the ranges are driven by the winter power and gas prices in the New England region. Without the New England region, the upper ends of the ranges for power and gas would be approximately $97 and $8.14, respectively, and would be approximately $76 for power proprietary trading.

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

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

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 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015, the proportion of expected generation hedged is for the major reportable segments was 98%-101%, 77%-80%, and 46%-49% 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 1,657 GWhs and 3,465 GWhs for the three and six months ended June 30, 2015, respectively, and 2,629 GWhs and 5,123 GWhs for the three and six months ended June 30, 2014, respectively, are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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 June 30, 2015, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and Exelon and Generation had $754 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 $2 million decrease in Exelon Consolidated pre-tax income for the six months ended June 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 June 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)	$	$ 10	$ 10	$ (10)	$ 10	$	$	$	$	$ 10
Mark-to-market derivative assets (noncurrent assets)	1	10	6	(3)	14	21			21	35
Total mark-to-market derivative assets	1	20	16	(13)	24	21			21	45
Mark-to-market derivative liabilities (current liabilities)	(9)	(5)	(9)	14	(9)					(9)
Mark-to-market derivative liabilities (noncurrent liabilities)	(5)		(5)	5	(5)					(5)
Total mark-to-market derivative liabilities	(14)	(5)	(14)	19	(14)					(14)
Total mark-to-market derivative net assets (liabilities)	$ (13)	$ 15	$ 2	$ 6	$ 10	$ 21	$	$	$ 21	$ 31

(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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(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.

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.

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Fair Value Hedges. For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in current earnings. Exelon includes the gain or loss on the hedged items and the offsetting loss or gain on the related interest rate swaps in interest expense as follows:

	Income Statement Location	Three Months Ended June 30, 2015 Gain (Loss) on Swaps	2014 Gain (Loss) on Swaps	2015 Gain (Loss) on Borrowings	2014 Gain (Loss) on Borrowings
Generation	Interest expense[(a)]	$	$ (3)	$	$ 2
Exelon	Interest expense	(11)	3	(12)	(3)

	Income Statement Location	Six Months Ended June 30, 2015 Gain (Loss) on Swaps	2014 Gain (Loss) on Swaps	2015 Gain (Loss) on Borrowings	2014 Gain (Loss) on Borrowings
Generation	Interest expense[(a)]	$ (1)	$ (8)	$	$ 1
Exelon	Interest expense	(2)	5	(4)	(7)

(a) For the three and six months ended June 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 six months ended June 30, 2014, the loss on Generation swaps included $4 million and $8 million realized in earnings, respectively, with an immaterial amount excluded from hedge effectiveness testing.

At June 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 $20 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 six months ended June 30, 2015, the impact on the results of operations as a result of the ineffectiveness from fair value hedges was a $4 million and $8 million gain, respectively. During the three and six months ended June 30, 2014, the impact on the results of operations as a result of the ineffectiveness from fair value hedges was a $5 million and $8 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 $502 million as of June 30, 2015 and expire in 2019. The swap was designated as a cash flow hedge in the fourth quarter of 2014. At June 30, 2015, the subsidiary had a $10 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

information regarding the financing. The swaps have a notional amount of $201 million as of June 30, 2015 and expire in 2020. The swaps are designated as cash flow hedges. At June 30, 2015, the subsidiary had a $2 million derivative liability related to the swaps.

During the three and six months ended June 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 June 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. The balance in Accumulated OCI was frozen as of the date of de-designation and will amortize into Interest expense over the remaining term of the forecasted transaction. All future changes in fair value are reflected in Interest expense. At June 30, 2015, the subsidiary had a $2 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 June 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. The balance in OCI was frozen as of the date of de-designation and will amortize into Interest expense over the remaining term of the forecasted transaction. All future changes in fair value are reflected in Interest expense. At June 30, 2015, the subsidiary had an immaterial derivative asset 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 June 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 $146 million in notional amounts of foreign currency exchange rate swaps that are marked-to-market to manage the exposure associated with international purchases of commodities in currencies other than U.S. dollars.

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

Fair value accounting guidance and disclosures about offsetting assets and liabilities requires the fair value of derivative instruments to be shown in the Notes to the Consolidated Financial Statements on a gross basis, even when the derivative instruments are subject to legally enforceable master netting agreements and qualify for net presentation in the Consolidated Balance Sheet. A master netting agreement is an agreement between two counterparties that may have derivative and non-derivative contracts with each other providing for the net settlement of all referencing contracts via one payment stream, which takes place as the contracts deliver, when collateral is requested or in the event of default. Generation s use of cash collateral is generally unrestricted,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015 and December 31, 2014, $2 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 June 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)	$ 4,398	$ 346	$ (3,349)	$ 1,395	$	$ 1,395
Mark-to-market derivative assets (noncurrent assets)	2,368	48	(1,640)	776		776
Total mark-to-market derivative assets	6,766	394	(4,989)	2,171		2,171
Mark-to-market derivative liabilities (current liabilities)	(3,793)	(347)	4,004	(136)	(20)	(156)
Mark-to-market derivative liabilities (noncurrent liabilities)	(2,291)	(55)	1,959	(387)	(203)	(590)
Total mark-to-market derivative liabilities	(6,084)	(402)	5,963	(523)	(223)	(746)
Total mark-to-market derivative net assets (liabilities)	$ 682	$ (8)	$ 974	$ 1,648	$ (223)	$ 1,425

(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 $297 million and $144 million, respectively, and current and noncurrent liabilities are shown net of collateral of $358 million and $175 million, respectively. The total cash collateral posted, net of cash collateral received and offset against mark-to-market assets and liabilities was $974 million at June 30, 2015.

(c) Includes current and noncurrent liabilities relating 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 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 June 30, 2015, no unrealized balance remains in accumulated OCI to be reclassified by Generation.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The tables below provide the activity of accumulated OCI related to cash flow hedges for the three and six months ended June 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 actual physical power sales, result in the ultimate recognition of net revenues at the contracted price.

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended June 30, 2015	**Income Statement Location**	**Generation Total Cash Flow Hedges**	**Exelon Total Cash Flow Hedges**
Accumulated OCI derivative gain at March 31, 2015		$ (23)	$ (22)
Effective portion of changes in fair value			1
Reclassifications from accumulated OCI to net income	Interest Expense	2	2
Accumulated OCI derivative gain at June 30, 2015		$ (21)	$ (19)

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Six Months Ended June 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		(6)	(10)
Reclassifications from accumulated OCI to net income	Other, net		16(a)
Reclassifications from accumulated OCI to net income	Interest Expense	5	5
Reclassifications from accumulated OCI to net income	Operating Revenues	(2)	(2)
Accumulated OCI derivative gain at June 30, 2015		$ (21)	$ (19)

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

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Three Months Ended June 30, 2014	**Income Statement Location**	**Generation Total Cash Flow Hedges**	**Exelon Total Cash Flow Hedges**

Accumulated OCI derivative gain at March 31, 2014		$ 88	$ 95
Effective portion of changes in fair value		(5)	(10)
Reclassifications from accumulated OCI to net income	Operating Revenues	(38)[(a)]	(38)[(a)]
Accumulated OCI derivative gain at June 30, 2014		$ 45	$ 47

(a) Amount is net of related income tax expense of $25 million for the three months ended June 30, 2014.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

		Total Cash Flow Hedge OCI Activity, Net of Income Tax	
Six Months Ended June 30, 2014	**Income Statement Location**	**Generation Total Cash Flow Hedges**	**Exelon Total Cash Flow Hedges**
Accumulated OCI derivative gain at December 31, 2013		$ 116	$ 120
Effective portion of changes in fair value		(9)	(11)
Reclassifications from accumulated OCI to net income	Operating Revenues	(62)[a]	(62)[a]
Accumulated OCI derivative gain at June 30, 2014		$ 45	$ 47

(a) Amount is net of related income tax expense of $40 million for the six months ended June 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 six months ended June 30, 2015. There were no gains recognized for the three months ended June 30, 2015. For the three and six months ended June 30, 2014, Exelon and Generation recognized a $63 million and $102 million pre-tax gain, respectively. Neither Exelon nor Generation will incur changes in cash flow hedge ineffectiveness in future periods as all energy-related cash flow hedge positions were de-designated prior to the merger date.

Economic Hedges (Exelon and Generation). These instruments represent hedges that economically mitigate exposure to fluctuations in commodity prices and include financial options, futures, swaps, physical forward sales and purchases, but for which the fair value or cash flow hedge elections were not made. 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 six months ended June 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 June 30, 2015	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**Total**
Change in fair value of commodity positions	$ 197	$ 110	$	$ 307	$	$ 307
Reclassification to realized at settlement of commodity positions	(167)	100		(67)		(67)
Net commodity mark-to-market gains (losses)	30	210		240		240
Change in fair value of treasury positions	(3)			(3)	114	111
Reclassification to realized at settlement of treasury positions	(2)			(2)	64	62

Net treasury mark-to-market gains (losses)	(5)			(5)	178	173
Net mark-to-market gains (losses)	$ 25	$ 210	$	$ 235	$ 178	$ 413

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Generation				HoldCo	Exelon
Six Months Ended June 30, 2015	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**Total**
Change in fair value of commodity positions	$ 377	$ 15	$	$ 392	$	$ 392
Reclassification to realized at settlement of commodity positions	(204)	203		(1)		(1)
Net commodity mark-to-market gains (losses)	173	218		391		391
Change in fair value of treasury positions	10			10	36	46
Reclassification to realized at settlement of treasury positions	(4)			(4)	64	60
Net treasury mark-to-market gains (losses)	6			6	100	106
Net mark-to-market gains (losses)	$ 179	$ 218	$	$ 397	$ 100	$ 497

	Generation				HoldCo	Exelon
Three Months Ended June 30, 2014	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**Total**
Change in fair value of commodity positions	$ (124)	$ 111	$	$ (13)	$	$ (13)
Reclassification to realized at settlement of commodity positions	45	(42)		3		3
Net commodity mark-to-market gains (losses)	(79)	69		(10)		(10)
Change in fair value of treasury positions	(3)		(1)	(4)		(4)
Reclassification to realized at settlement of treasury positions	(1)			(1)		(1)
Net treasury mark-to-market gains (losses)	(4)		(1)	(5)		(5)
Net mark-to-market gains (losses)	$ (83)	$ 69	$ (1)	$ (15)	$	$ (15)

	Generation				HoldCo	Exelon
Six Months Ended June 30, 2014	**Operating Revenues**	**Purchased Power and Fuel**	**Interest Expense**	**Total**	**Interest Expense**	**Total**
Change in fair value of commodity positions	$ (975)	$ 282	$	$ (693)	$	$ (693)
Reclassification to realized at settlement of commodity positions	137	(183)		(46)		(46)
Net commodity mark-to-market gains (losses)	(838)	99		(739)		(739)
Change in fair value of treasury positions	(4)		(1)	(5)		(5)

Reclassification to realized at settlement of treasury positions	(1)			(1)		(1)
Net treasury mark-to-market gains (losses)	(5)		(1)	(6)		(6)
Net mark-to-market gains (losses)	$ (843)	$ 99	$ (1)	$ (745)	$	$ (745)

Proprietary Trading Activities (Exelon and Generation). For the three and six months ended June 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

90

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Change in fair value of commodity positions	Operating Revenues	$ 7	$ 1	$ 8	$
Reclassification to realized at settlement of commodity positions	Operating Revenues	(7)	(8)	(5)	(7)
Net commodity mark-to-market gains (losses)	Operating Revenues		(7)	3	(7)
Change in fair value of treasury positions	Operating Revenues			4	(1)
Reclassification to realized at settlement of treasury positions	Operating Revenues	(2)	1	(6)	1
Net treasury mark-to-market gains (losses)	Operating Revenues	(2)	1	(2)	
Total Net mark-to-market gains (losses)	Operating Revenues	$ (2)	$ (6)	$ 1	$ (7)

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

The Registrants would be exposed to credit-related losses in the event of non-performance by counterparties that enter into derivative instruments. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. For energy-related derivative instruments, Generation enters into enabling agreements that allow for payment netting with its counterparties, which reduces Generation s exposure to counterparty risk by providing for the offset of amounts payable to the counterparty against amounts receivable from the counterparty. Typically, each enabling agreement is for a specific commodity and so, with respect to each individual counterparty, netting is limited to transactions involving that specific commodity product, except where master netting agreements exist with a counterparty that allow for cross product netting. In addition to payment netting language in the enabling agreement, Generation s credit department establishes credit limits, margining thresholds and collateral requirements for each counterparty, which are defined in the derivative contracts. Counterparty credit limits are based on an internal credit review process that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings by credit rating agencies, and risk management capabilities. To the extent that a counterparty s margining thresholds are exceeded, the counterparty is required to post collateral with Generation as specified in each enabling agreement. Generation s credit department monitors current and forward credit exposure to counterparties and their affiliates, both on an individual and an aggregate basis.

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 June 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 $36 million, $35 million and $31 million, as of June 30, 2015, respectively.

Rating as of June 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	$ 1,643	$ 24	$ 1,619	1	$ 444
Non-investment grade	55	18	37		
No external ratings					
Internally rated investment grade	498		498		
Internally rated non-investment grade	48	6	42		
Total	$ 2,244	$ 48	$ 2,196	1	$ 444

Net Credit Exposure by Type of Counterparty	As of June 30, 2015
Financial institutions	$ 383
Investor-owned utilities, marketers, power producers	880
Energy cooperatives and municipalities	881
Other	52
Total	$ 2,196

(a) As of June 30, 2015, credit collateral held from counterparties where Generation had credit exposure included $30 million of cash and $18 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 June 30, 2015, ComEd s net credit exposure to suppliers was immaterial.

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

PECO s supplier master agreements that govern the terms of its electric supply procurement contracts, which define a supplier s performance assurance requirements, allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier s lowest credit rating from the major credit rating agencies and the supplier s tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day a transaction is executed, compared to the current forward price curve for energy. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post collateral to the extent the credit exposure is greater than the supplier s unsecured credit limit. The unsecured credit used by the suppliers represents PECO s net credit exposure. As of June 30, 2015, PECO is currently holding $3 million in collateral from suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 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 June 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 June 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.

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,

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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	June 30, 2015	December 31, 2014
Gross Fair Value of Derivative Contracts Containing this Feature[(a)]	$ (1,558)	$ (1,433)
Offsetting Fair Value of In-the-Money Contracts Under Master Netting Arrangements[(b)]	1,275	1,140
Net Fair Value of Derivative Contracts Containing This Feature[(c)]	$ (283)	$ (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 $1,020 million and letters of credit posted of $511 million and cash collateral held of $39 million and letters of credit held of $23 million as of June 30, 2015 for counterparties with derivative positions. Generation had cash collateral posted of $1,497 million and letters of credit posted of $672 million and cash collateral held of $77 million and letters of credit held of $24 million at December 31, 2014 for counterparties with derivative positions. In the event of a credit downgrade below investment grade (i.e., to BB+ by S&P or Ba1 by Moody s), Generation would have been required to post additional collateral of $2.2 billion and $2.4 billion as of June 30, 2015 and December 31, 2014, respectively. These amounts represent the potential additional collateral required after giving consideration to offsetting derivative and non-derivative positions under master netting agreements.

Generation s and Exelon s interest rate swaps contain provisions that, in the event of a merger, if Generation s debt ratings were to materially weaken, it would be in violation of these provisions, resulting in the ability of the counterparty to terminate the agreement prior to maturity. Collateralization would not be required under any circumstance. Termination of the agreement could result in a settlement payment by Exelon or the counterparty on any interest rate swap in a net liability position. The settlement amount would be equal to the fair value of the swap on the termination date. As of June 30, 2015, Generation s swaps were in an asset with a fair value of $10 million and Exelon s swaps were in a liability position, with a fair value of $31 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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 30, 2015, ComEd held approximately $2 million collateral from suppliers in association with energy procurement contracts. Under the terms of ComEd s annual renewable energy contracts, collateral postings are required to cover a fixed value for RECs only. In addition, under the terms of ComEd s long-term renewable energy contracts, collateral postings are required from suppliers for both RECs and energy. The REC portion is a fixed value and the energy portion is one-sided from suppliers should the forward market prices exceed contract prices. As of June 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 June 30, 2015, PECO was not required to post collateral for any of these agreements. If PECO lost its investment grade credit rating as of June 30, 2015, PECO could have been required to post approximately $20 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 June 30, 2015, BGE was not required to post collateral for any of these agreements. If BGE lost its investment grade credit rating as of June 30, 2015, BGE could have been required to post approximately $34 million of collateral to its counterparties.

11. Debt and Credit Agreements (Exelon, Generation, ComEd, PECO and BGE)

Short-Term Borrowings

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

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

Commercial Paper Borrowings	June 30, 2015	December 31, 2014
Exelon Corporate	$	$
Generation		
ComEd	503	304
PECO		
BGE		120

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Credit Facilities

Exelon had bank lines of credit under committed credit facilities at June 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 expire on October 16, 2015. These facilities are solely utilized to issue letters of credit. As of June 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.

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

Borrowings under Exelon Corporate s, Generation s, ComEd s, PECO s and BGE s credit 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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Long-Term Debt

Issuance of Long-Term Debt

During the six months ended June 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)(b)]	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)(b)]	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)(b)]	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 licensers
Generation	Senior Unsecured Notes[(c)]	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
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		2.50 - 2.70%	2019 - 2020	$ 435	General corporate purposes

	Tax Exempt Pollution Control Revenue Bonds[d]				
Generation	Albany Green Energy Project Financing	LIBOR + 1.25%	November 17, 2017	$ 50	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

97

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(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) The 2025 notes, the 2035 notes and the 2045 notes must be redeemed upon the earlier of (i) December 31, 2015, if the PHI acquisition is not consummated on or prior to such date, or (ii) the date on which the Merger Agreement relating to the PHI acquisition is terminated.
(c) 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.
(d) The Tax Exempt Pollution Control Revenue Bonds have a mandatory put date that ranges from March 1, 2019 - September 1, 2020.

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.

Albany Green Energy Project (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.

During the six months ended June 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	3.35%	June 30, 2018	$ 38	Procurement of uranium
Generation	ExGen Renewables I Nonrecourse Debt	LIBOR + 4.25%	February 6, 2021	$ 300	General corporate purposes
ComEd	First Mortgage Bonds Series 115	2.15%	January 15, 2019	$ 300	Refinance maturing mortgage bonds and general corporate purposes
ComEd	First Mortgage Bonds Series 116	4.70%	January 15, 2044	$ 350	Refinance maturing mortgage bonds and general corporate purposes

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 six months ended June 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
Generation[a]	Senior Unsecured Notes	4.55%	June 15, 2015	$ 550
Generation	CEU Upstream Nonrecourse Debt	LIBOR + 2.25%	January 14, 2019	$ 2
Generation	AVSR DOE Nonrecourse Debt	2.29%-3.56%	January 5, 2037	$ 6
Generation	Kennett Square Capital Lease	7.83%	September 20, 2020	$ 2
Generation	Continental Wind Nonrecourse Debt	6.00%	February 28, 2033	$ 10
Generation	ExGen Texas Power Nonrecourse Debt	LIBOR + 4.75%	September 8, 2021	$ 3
Generation	ExGen Renewables I Nonrecourse Debt	4.49%	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 July 6, 2015, Generation paid down $6 million of principal of its 2.29%-3.55% AVSR DOE Nonrecourse debt.

During the six months ended June 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	$ 11
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	$ 1
Generation	Clean Horizons Solar Nonrecourse Debt	2.56%	September 7, 2030	$ 1
Generation	Sacramento Solar Nonrecourse Debt	2.56%	December 31, 2030	$ 1
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

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

99

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 were recorded to Long-term debt, representing the obligation to make contract payments, with an offsetting reduction to Common stock. The obligation for the contract payments will be accreted to interest expense over the 3 year period ending in 2017 in Exelon s Consolidated Statement of Operations and Comprehensive Income. The Long-term debt recorded for the contract payments is considered a non-cash financing transaction that was excluded from Exelon s Consolidated Statements of Cash Flows. Until settlement of the equity purchase contract, earnings per share dilution resulting from the equity unit issuance will be determined under the treasury stock method.

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

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 June 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	3.9	3.4	5.6	1.4	5.3
Qualified nuclear decommissioning trust fund income	(1.0)	(1.7)			
Domestic production activities deduction	(2.0)	(3.4)			
Health care reform legislation					0.1
Amortization of investment tax credit, net deferred taxes	(0.6)	(0.9)	(0.3)	(0.1)	(0.2)
Plant basis differences	(1.0)		(0.1)	(9.0)	(0.5)
Production tax credits and other credits	(1.3)	(2.2)			
Noncontrolling interest	(0.4)	(0.6)			
Other	1.4	2.0	0.5	0.5	0.8
Effective income tax rate	34.0%	31.6%	40.7%	27.8%	40.5%

For the Six Months Ended June 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	3.2	3.0	5.3	1.3	5.3
Qualified nuclear decommissioning trust fund income	0.6	0.9			
Domestic production activities deduction	(2.1)	(3.4)			
Health care reform legislation					0.2
Amortization of investment tax credit, net deferred taxes	(0.8)	(1.1)	(0.3)	(0.1)	(0.1)
Plant basis differences	(1.1)		(0.2)	(7.5)	(0.3)
Production tax credits and other credits	(1.6)	(2.5)			

Noncontrolling interest	(0.6)	(0.8)			
Other	0.8	0.6	0.4	0.2	
Effective income tax rate	33.4%	31.7%	40.2%	28.9%	40.1%

100

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the Three Months Ended June 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	2.1	1.7	4.6	(0.5)	4.1
Qualified nuclear decommissioning trust fund income	4.1	6.0			
Domestic production activities deduction	(2.0)	(2.9)			
Health care reform legislation			0.2		0.2
Amortization of investment tax credit, net deferred taxes	(0.4)	(0.5)	(0.3)	(0.1)	(0.7)
Plant basis differences	(1.6)		(0.4)	(13.2)	5.1
Production tax credits and other credits	(0.8)	(1.1)			
Noncontrolling interest	(2.0)	(2.9)			
Other	(1.2)	(0.4)	0.2	0.3	(1.3)
Effective income tax rate	33.2%	34.9%	39.3%	21.5%	42.4%

For the Six Months Ended June 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	(0.6)	(14.7)	5.0	0.4	5.0
Qualified nuclear decommissioning trust fund income	5.9	27.7			
Domestic production activities deduction	(3.2)	(14.8)			
Health care reform legislation	0.1		0.2		0.2
Amortization of investment tax credit, net deferred taxes	(1.2)	(4.9)	(0.3)	(0.1)	(0.3)
Plant basis differences	(3.0)		(0.5)	(10.8)	0.4
Production tax credits and other credits	(2.4)	(11.1)			
Noncontrolling interest	(1.9)	(8.8)			
Other	(3.1)	(8.9)	0.2	0.3	0.1
Effective income tax rate	25.6%	(0.5)%	39.6%	24.8%	40.4%

Accounting for Uncertainty in Income Taxes

Exelon, Generation, ComEd, PECO, and BGE have $1,289 million, $745 million, $146 million, $0 million, and $120 million, of unrecognized tax benefits as of June 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 June 30, 2015 reflect a decrease at Exelon, Generation, and PECO primarily attributable to the disallowed AmerGen claims discussed below. The unrecognized tax benefits as of June 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 (Exelon and Generation)

AmerGen filed income tax refund claims taking the position that nuclear decommissioning liabilities assumed as part of its acquisition of nuclear power plants are taken into account in determining the tax basis in the assets it acquired. The additional basis results primarily in reduced capital gains or increased capital losses on the sale of assets in nonqualified decommissioning funds and increased tax depreciation and amortization deductions. The IRS disagrees with this position and disallowed AmerGen s claims. In early 2009, Generation filed a complaint in the United States Court of Federal Claims to contest this determination. On September 17,

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 its total unrecognized tax benefits by $661 million in the first quarter of 2015. This change in unrecognized tax benefits had no impact on Exelon s or Generation s effective tax rate.

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

Like-Kind Exchange

As of June 30, 2015, Exelon and ComEd have approximately $395 million and $145 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 June 30, 2015, Exelon, Generation, and BGE have approximately $347 million, $227 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 $227 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.

In July 2015, certain of these unrecognized state tax benefits were effectively settled resulting in a reduction of $45 million of tax expense and $21 million of accrued interest (after-tax) at Generation in the third quarter of 2015.

Other Income Tax Matters

Like-Kind Exchange

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

In the event of a fully successful IRS challenge to Exelon s like-kind exchange position, the potential tax and after-tax interest, exclusive of penalties, that could become currently payable as of June 30, 2015 may be as much as $810 million, of which approximately $310 million would be attributable to ComEd after consideration of Exelon s agreement to hold ComEd harmless, and the balance at Exelon. Litigation could take several years such that the estimated cash and interest impacts would likely change by a material amount.

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 applied to satisfy taxes owed for any tax year. In the event of a fully successful IRS challenge to Exelon s like-kind exchange position, the amount placed on deposit will be redesignated to reduce the amount of tax and after-tax interest discussed in the preceding paragraph.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 June 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[(b)]	55
Accretion expense	189
Costs incurred to decommission retired plants	(1)
Nuclear decommissioning ARO at June 30, 2015[(a)]	$ 7,204

(a) Includes $7 million and $8 million as the current portion of the ARO at June 30, 2015 and December 31, 2014 respectively, which is included in Other current liabilities on Exelon s and Generation s Consolidated Balance Sheets.
(b) Represents a purchase accounting adjustment to the fair value of the CENG ARO liability as of April 1, 2014, the date of consolidation. See Note 6 Investment in Constellation Energy Nuclear Group, LLC for additional information.

Nuclear Decommissioning Trust Fund Investments

At June 30, 2015 and December 31, 2014, Exelon and Generation had NDT fund investments totaling $10,607 million and $10,537 million, respectively.

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

	Exelon and Generation			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net unrealized gains (losses) on decommissioning trust funds Regulatory Agreement Units[(a)]	$ (133)	$ 172	$ (85)	$ 234
Net unrealized gains (losses) on decommissioning trust funds Non-Regulatory Agreement Units[(b)(c)]	(96)	128	(56)	141

(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 $10 million of net unrealized gains related to the Zion Station pledged assets for the three months ended June 30, 2014 and $9 million and $20 million of net unrealized gains related to the Zion Station pledged assets for the six months ended June 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.

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

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 $88 million, which is included within the nuclear decommissioning ARO at June 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 June 30, 2015 and December 31, 2014:

	Exelon and Generation	
	June 30, 2015	December 31, 2014
Carrying value of Zion Station pledged assets	$ 264	$ 319
Payable to Zion Solutions[(a)]	241	292
Current portion of payable to Zion Solutions[(b)]	106	137
Cumulative withdrawals by Zion Solutions to pay decommissioning costs	731	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.

105

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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.

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 six months ended June 30, 2015 and 2014.

	Pension Benefits Three Months Ended June 30,		Other Postretirement Benefits Three Months Ended June 30,	
	2015[(a)]	2014[(a)]	2015[(a)]	2014[(a)]
Service cost	$ 81	$ 74	$ 29	$ 30
Interest cost	178	190	42	47
Expected return on assets	(256)	(251)	(37)	(38)
Amortization of:				
Prior service cost (benefit)	4	4	(44)	(30)
Actuarial loss	142	104	21	12
Net periodic benefit cost	$ 149	$ 121	$ 11	$ 21

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Pension Benefits		Other Postretirement Benefits	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2015[(a)]	2014[(a)]	2015[(a)]	2014[(a)]
Service cost	$ 163	$ 143	$ 59	$ 62
Interest cost	355	373	83	103
Expected return on assets	(513)	(492)	(75)	(76)
Amortization of:				
Prior service cost (benefit)	7	7	(88)	(34)
Actuarial loss	285	209	41	20
Net periodic benefit cost	$ 297	$ 240	$ 20	$ 75

(a) For the three months ended June 30, 2015, the cost for pension benefits and other postretirement benefits related to CENG were $3 million and $3 million, respectively. For the six months ended June 30, 2015, the cost for pension benefits and other postretirement benefits related to CENG were $5 million and $6 million, respectively. For the period of April 1, 2014 to June 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.

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 six months ended June 30, 2015 and 2014.

Pension and Other Postretirement Benefit Costs	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Generation[(a)]	$ 68	$ 63	$ 133	$ 139
ComEd	51	40	103	96
PECO	10	9	19	21
BGE	17	17	33	33
BSC[(b)]	14	13	29	26

(a) For the three and six months ended June 30, 2015, the costs related to CENG were $6 million and $11 million, respectively. For the period of April 1, 2014 to June 30, 2014, amounts include $5 million related to CENG.

(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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Defined Contribution Savings Plans

The Registrants participate in various 401(k) defined contribution savings plans that are sponsored by Exelon. The plans are qualified under applicable sections of the IRC and allow employees to contribute a portion of their pre-tax income in accordance with specified guidelines. All Registrants match a percentage of the employee contributions up to certain limits. The following table presents the matching contributions to the savings plans during the three and six months ended June 30, 2015 and 2014:

Savings Plan Matching Contributions	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Exelon[(a)]	$ 38	$ 19	$ 60	$ 48
Generation[(a)]	20	10	33	24
ComEd	8	5	13	12
PECO	3	2	4	4
BGE	3	1	5	4
BSC[(b)]	4	1	5	4

(a) Includes $3 million and $4 million, respectively, related to CENG for the three and six months ended June 30, 2015. For the period of April 1, 2014 to June 30, 2014, amounts include $1 million related to CENG.
(b) These amounts primarily represent amounts billed to Exelon s subsidiaries through intercompany allocations. These costs are not included in the Generation, ComEd, PECO or BGE amounts above.

15. Severance (Exelon, Generation, ComEd, PECO and BGE)

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

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 six months ended June 30, 2015 and 2014, the Registrants recorded the following severance costs associated with these ongoing severance benefits within Operating and maintenance expense in their Consolidated Statements of Operations and Comprehensive Income:

	Exelon	Generation	ComEd	PECO	BGE
Three Months Ended					
June 30, 2015	$ 1	$ (1)	$	$	$
June 30, 2014	4	2			

Six Months Ended					
June 30, 2015	$ 21	$ 17	$	$	$
June 30, 2014	6	4			

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The severance liability balances associated with these ongoing severance benefits as of June 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 six months ended June 30, 2015 and 2014:

Six Months Ended June 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	(10)		(29)	(9)		(48)
Amounts reclassified from AOCI[b]	19		87			106
Net current-period OCI	9		58	(9)		58
Ending balance	$ (19)	$ 3	$ (2,582)	$ (28)	$	$ (2,626)
Generation[a]						
Beginning balance	$ (18)	$ 1	$	$ (19)	$	$ (36)
OCI before reclassifications	(6)	1		(9)		(14)
Amounts reclassified from AOCI[b]	3					3
Net current-period OCI	(3)	1		(9)		(11)
Ending balance	$ (21)	$ 2	$	$ (28)	$	$ (47)
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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 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	(11)	1	246	(1)	11	246
Amounts reclassified from AOCI[b]	(62)		66		(116)	(112)
Net current-period OCI	(73)	1	312	(1)	(105)	134
Ending balance	$ 47	$ 3	$ (1,948)	$ (11)	$ 3	$ (1,906)
Generation[a]						
Beginning balance	$ 114	$ 2	$	$ (10)	$ 108	$ 214
OCI before reclassifications	(8)	(1)		(1)	11	1
Amounts reclassified from AOCI[b]	(62)				(116)	(178)
Net current-period OCI	(70)	(1)		(1)	(105)	(177)
Ending balance	$ 44	$ 1	$	$ (11)	$ 3	$ 37
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.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Three Months Ended June 30, 2015

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains (losses) on hedging activity			
Other cash flow hedges	$ (2)	$ (2)	Interest expense
	(2)	(2)	Total before tax
			Tax benefit
	$ (2)	$ (2)	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 19	$	
Actuarial losses[b]	(90)		
	(71)		Total before tax
	27		Tax benefit
	$ (44)	$	Net of tax
Total Reclassifications for the period	$ (46)	$ (2)	Net of Tax

Six Months Ended June 30, 2015

Details about AOCI components	Items reclassified out of AOCI[a]		Affected line item in the Statements of Operations and Comprehensive Income
	Exelon	Generation	
Gains (losses) on hedging activity			
Terminated interest rate swaps[c]	$ (26)	$	Other, net
Energy related hedges	2	2	Operating revenues
Other cash flow hedges	(5)	(5)	Interest expense
	(29)	(3)	Total before tax
	10		Tax benefit
	$ (19)	$ (3)	Net of tax

Amortization of pension and other postretirement benefit plan items						
Prior service costs[(b)]	$	38	$			
Actuarial losses[(b)]		(180)				
		(142)				Total before tax
		55				Tax benefit
	$	(87)	$			Net of tax
Total Reclassifications for the period	$	(106)	$	(3)		Net of Tax

111

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Three months ended June 30, 2014

Details about AOCI components	Items reclassified out of AOCI[a] Exelon	Generation	Affected line item in the Statements of Operations and Comprehensive Income
Gains on hedging activity			
Energy related hedges	$ 63	$ 63	Operating revenues
	63	63	Total before tax
	(25)	(25)	Tax (expense)
	$ 38	$ 38	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[b]	$ 12	$	
Actuarial losses[b]	(61)		
	(49)		Total before tax
	18		Tax benefit
	$ (31)	$	Net of tax
Equity investments			
Reversal of CENG equity method AOCI	$ 193	$ 193	Gain on consolidation of CENG
	193	193	Total before tax
	(77)	(77)	Tax benefit
	$ 116	$ 116	Net of tax
Total reclassifications for the period	$ 123	$ 154	Net of Tax

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2014

Details about AOCI components	Items reclassified out of AOCI[(a)] Exelon	Generation	Affected line item in the Statements of Operations and Comprehensive Income
Gains on hedging activity			
Energy related hedges	$ 102	$ 102	Operating revenues
	102	102	Total before tax
	(40)	(40)	Tax (expense)
	$ 62	$ 62	Net of tax
Amortization of pension and other postretirement benefit plan items			
Prior service costs[(b)]	$ 10	$	
Actuarial losses[(b)]	(117)		
	(107)		Total before tax
	41		Tax benefit
	$ (66)	$	Net of tax
Equity investments			
Reversal of CENG equity method AOCI	$ 193	$ 193	Gain on consolidation of CENG
	193	193	Total before tax
	(77)	(77)	Tax benefit
	$ 116	$ 116	Net of tax
Total reclassifications for the period	$ 112	$ 178	Net of Tax

(a) All amounts are net of tax. Amounts in parentheses represent a decrease in net income.
(b) This accumulated other comprehensive income component is included in the computation of net periodic pension and OPEB cost (see Note 14 Retirement Benefits for additional details).
(c) In January 2015, in connection with Generation s $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon s Consolidated Statement of Operations and Comprehensive Income.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents income tax expense (benefit) allocated to each component of other comprehensive income (loss) during the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Exelon				
Pension and non-pension postretirement benefit plans:				
Prior service benefit reclassified to periodic benefit cost	$ 8	$ 5	$ 15	$ 5
Actuarial loss reclassified to periodic cost	(35)	(23)	(69)	(46)
Pension and non-pension postretirement benefit plans valuation adjustment		(166)	17	(159)
Change in unrealized (gain) loss on cash flow hedges	(2)	28	(6)	48
Change in unrealized income on equity investments		77		70
Change in unrealized loss on marketable securities	1		1	
Total	$ (28)	$ (79)	$ (42)	$ (82)
Generation				
Change in unrealized (gain) loss on cash flow hedges	$ (1)	$ 25	$ 1	$ 44
Change in unrealized income on equity investments		77		70
Change in marketable securities			1	(2)
Total	$ (1)	$ 102	$ 2	$ 112

17. Common Stock (Exelon)

Equity Securities Offering

In June 2014, Exelon marketed an equity offering of 57.5 million shares of its common stock at a public offering price of $35 per share and entered into forward sale agreements with two counterparties. In July 2015, Exelon settled the forward sale agreements by the issuance of 57.5 million shares of Exelon common stock. Exelon received net cash proceeds of $1.87 billion, which was calculated based on a forward price of $32.48 per share as specified in the forward sale agreements. Exelon will use the net proceeds to fund the pending acquisition of PHI and related costs and expenses, and for general corporate purposes.

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

18. Earnings Per Share and Equity (Exelon)

Earnings per Share (Exelon)

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income attributable to common shareholders	$ 638	$ 522	$ 1,331	$ 612
Average common shares outstanding basic	863	860	862	860
Potentially dilutive effect of stock options, performance share awards and restricted stock	3	4	4	3
Average common shares outstanding diluted	866	864	866	863

The number of stock options not included in the calculation of diluted common shares outstanding due to their antidilutive effect was approximately 13 million and 15 million for the three and six months ended June 30, 2015, respectively, and 16 million for the three and six months ended June 30, 2014. The number of equity units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect was 1 million for the three and six months ended June 30, 2015 since issuance. Additionally, there were no forward units related to the PHI merger not included in the calculation of diluted common shares outstanding due to their antidilutive effect for the three and six months ended June 30, 2015 since issuance. Refer to Note 17 Common Stock for further information regarding the equity units and equity forward units.

Under share repurchase programs, 35 million shares of common stock are held as treasury stock with a cost of $2.3 billion as of June 30, 2015. In 2008, Exelon management decided to defer indefinitely any share repurchases.

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Commitments

Energy Commitments

As of June 30, 2015, Generation s commitments relating to its purchases from unaffiliated utilities and others of energy, capacity, transmission rights and RECs, are as indicated in the following table:

	Net Capacity Purchases[a]	REC Purchases[b]	Transmission Rights Purchases[c]	Total
2015	$ 218	$ 58	$ 7	$ 283
2016	280	288	15	583
2017	207	187	16	410
2018	96	72	17	185
2019	101	11	18	130
Thereafter	263	1	38	302
Total	$ 1,165	$ 617	$ 111	$ 1,893

(a) Net capacity purchases include PPAs and other capacity contracts including those that are accounted for as operating leases. Amounts presented in the commitments represent Generation s expected payments under these arrangements at June 30, 2015, net of fixed capacity payments expected to be received (capacity offsets) by Generation under contracts to resell such acquired capacity to third parties under long-term capacity sale contracts. As of June 30, 2015, capacity offsets were $75 million, $146 million, $149 million, $150 million, $151 million, and $604 million for years 2015, 2016, 2017, 2018, 2019, and thereafter, respectively. Expected payments include certain fixed capacity charges which may be reduced based on plant availability.

(b) The table excludes renewable energy purchases that are contingent in nature.

(c) Transmission rights purchases include estimated commitments for additional transmission rights that will be required to fulfill firm sales contracts.

ComEd s, PECO s and BGE s electric supply procurement, curtailment services, REC and AEC purchase commitments, as applicable, as of June 30, 2015 are as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
ComEd							
Electric supply procurement[a]	$ 697	$ 251	$ 262	$ 163	$ 21	$	$
Renewable energy and RECs[b]	1,481	38	76	77	78	79	1,133
PECO							
Electric supply procurement[c]	671	368	270	33			
AECs[d]	13	2	2	2	2	2	3
BGE							
Electric supply procurement[e]	1,389	462	675	252			

Curtailment services[(f)]	95	20	34	29	12

(a) ComEd entered into various contracts for the procurement of electricity that started to expire in 2012, and will continue to expire through 2018. ComEd is permitted to recover its electric supply procurement costs from retail customers with no mark-up. As of June 30, 2015, ComEd has completed the ICC-approved procurement process for a portion of its energy requirements through the periods ending May 31, 2015, 2016 and 2017.

(b) Primarily related to ComEd 20-year contracts for renewable energy and RECs that began in June 2012. ComEd is permitted to recover its renewable energy and REC costs from retail customers with no mark-up. The commitments represent the maximum settlements with suppliers for renewable energy and RECs under the existing contract terms.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(c) PECO entered into various contracts for the procurement of electric supply to serve its default service customers that expire between 2015 and 2017. PECO is permitted to recover its electric supply procurement costs from default service customers with no mark-up in accordance with its PAPUC-approved DSP Programs. See Note 5 Regulatory Matters for additional information.
(d) PECO is subject to requirements related to the use of alternative energy resources established by the AEPS Act. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information.
(e) BGE entered into various contracts for the procurement of electricity that expire between 2015 through 2017. The cost of power under these contracts is recoverable under MDPSC approved fuel clauses. See Note 3 Regulatory Matters of the Exelon 2014 10-K for additional information.
(f) BGE has entered into various contracts with curtailment services providers related to transactions in PJM s capacity market. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information.

Fuel Purchase Obligations

In addition to the energy commitments described above, Generation has commitments to purchase fuel supplies for nuclear and fossil generation. Since the second quarter of 2014, 100% of CENG s nuclear fuel commitments are disclosed within the Generation line below, since CENG is now fully consolidated by Generation. PECO and BGE have commitments to purchase natural gas related to transportation, storage capacity and services to serve customers in their gas distribution service territory. As of June 30, 2015, these net commitments were as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Generation	$ 8,884	$ 726	$ 1,129	$ 1,078	$ 969	$ 880	$ 4,102
PECO	375	65	107	66	46	20	71
BGE	622	52	103	92	69	61	245

Other Purchase Obligations

The Registrants other purchase obligations as of June 30, 2015, which primarily represent commitments for services, materials and information technology, are as follows:

		Expiration within					
	Total	2015	2016	2017	2018	2019	2020 and beyond
Exelon	$ 1,422	$ 342	$ 421	$ 220	$ 77	$ 80	$ 282
Generation[(a)]	339	79	95	46	33	24	62
ComEd[(b)]	356	153	166	8	7	7	15
PECO[(b)]	21	5	5	2	2	2	5
BGE[(b)]	302	75	116	111			

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

Construction Commitments

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Generation completed the construction of the Perryman 6 expansion in Perryman, Maryland, which began commercial operation in June 2015. As of June 30, 2015, Generation has no further material remaining construction commitments for the project. This project will satisfy a portion of Exelon s commitment to Maryland. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

Since the third quarter of 2014, Generation executed contracts associated with the construction of new combined-cycle gas turbine units in Texas. The remaining commitment is approximately $736 million under these contracts and achievement of commercial operations is expected in 2017.

Since the fourth quarter of 2014, Generation executed contracts associated with the construction of the 30 MW Fair Wind project in western Maryland. The remaining commitment is approximately $16 million under these contracts and achievement of commercial operations is expected in 2015. This project will satisfy a portion of Exelon s 125 MW Tier I land-based renewables commitment made to Maryland. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for additional information on commitments to develop or assist in development of new generation in Maryland resulting from the Constellation merger.

Since the fourth quarter of 2014, Generation executed contracts associated with the construction of the 78 MW Sendero Wind project in southern Texas. The remaining commitment is approximately $49 million under these contracts and achievement of commercial operations is expected in 2015.

During the second quarter of 2015, Generation executed contracts associated with the construction of a 50 MW biomass facility in Georgia. The remaining commitment under these contracts is approximately $170 million and achievement of commercial operations is expected in 2017.

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

Constellation Merger Commitments

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

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

The direct investment commitment also includes $575 million to $650 million relating to Exelon and Generation s development or assistance in the development of 275 300 MWs of new generation in Maryland, which is expected to be completed within a period of 10 years. Exelon and Generation have incurred $314 million towards satisfying the commitment for new generation development in the state of Maryland, with

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

approximately 160 MW of the new generation commencing with commercial operations to date. The MDPSC order contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed or certain specified provisions are elected, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets and, therefore, will be primarily capital in nature and recognized as incurred. However, during the third quarter of 2014, the conditions associated with one of the generation development commitments changed such that Exelon and Generation now believe that the most likely outcome will involve making subsidy payments and/or liquidated damages payments rather than constructing the specified generating plant. As a result, Exelon and Generation recorded a pre-tax $44 million loss contingency related to this generation development commitment which is included in Operating and maintenance expense in Exelon s and Generation s Consolidated Statements of Operations and Comprehensive Income. While this $44 million loss contingency represents Generation s best estimate of the future obligation, it is reasonably possible that Exelon and Generation could ultimately be required to make cumulative subsidy payments of up to a maximum of approximately $105 million over a 20-year period dependent on actual generating output from a successfully constructed generating plant. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for additional information regarding the Constellation merger commitments.

Equity Investment Commitments

As part of Generation s investments in technology development, Generation enters into equity purchase agreements that include commitments to invest additional equity through incremental payments to fund the anticipated needs of the planned operations of the associated companies. The commitment includes approximately $20 million of in-kind services. As of June 30, 2015, Generation s estimated commitment relating to its equity purchase agreements, including in-kind services contributions, is anticipated to be as follows:

	Total
2015	$ 77
2016	254
2017	23
2018	7
2019	2
Total	$ 363

Contingencies

Commercial Commitments

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

	Exelon	Generation	ComEd	PECO	BGE
Letters of credit (non-debt)[(a)]	$ 1,568	$ 1,502	$ 18	$ 22	$ 1
Guarantees	5,824[(b)]	3,115[(c)]	203[(d)]	188[(e)]	263[(f)]
Nuclear insurance premiums[(g)]	3,057	3,057			
Underwriters discount[(h)]	60				
Total commercial commitments	$ 10,509	$ 7,674	$ 221	$ 210	$ 264

119

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Non-debt letters of credit maintained to provide credit support for certain transactions as requested by third parties.
(b) Primarily reflects parental guarantees issued on behalf of Generation to allow the flexibility needed to conduct business with counterparties without having to post other forms of collateral. Also reflects guarantees issued to ensure performance under specific contracts, preferred securities of financing trusts, property leases, indemnifications, NRC minimum funding assurance requirements and miscellaneous guarantees. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $674 million at June 30, 2015, which represents the total amount Exelon could be required to fund based on June 30, 2015 market prices.
(c) Primarily reflects guarantees issued to ensure performance under energy marketing and other specific contracts. The estimated net exposure for obligations under commercial transactions covered by these guarantees was $460 million at June 30, 2015, which represents the total amount Generation could be required to fund based on June 30, 2015 market prices.
(d) Primarily reflects full and unconditional guarantees of $200 million Trust Preferred Securities of ComEd Financing III, which is a 100% owned finance subsidiary of ComEd.
(e) Primarily reflects full and unconditional guarantees of $178 million Trust Preferred Securities of PECO Trust III and IV, which are 100% owned finance subsidiaries of PECO.
(f) Primarily reflects full and unconditional guarantees of $250 million Trust Preferred Securities of BGE Capital Trust II, which is a 100% owned finance subsidiary of BGE.
(g) Represents the maximum amount that Generation would be required to pay for retrospective premiums in the event of nuclear disaster at any domestic site, including CENG sites, under the Secondary Financial Protection pool as required under the Price-Anderson Act as well as the current aggregate annual retrospective premium obligation that could be imposed by NEIL. See the Nuclear Insurance section within this note for additional details on Generation s nuclear insurance premiums.
(h) Represents the underwriters discount for Exelon s forward equity transaction. See Note 17 Common Stock for further details of the equity securities offering.

Nuclear Insurance (Exelon and Generation)

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

The Price-Anderson Act was enacted to ensure the availability of funds for public liability claims arising from an incident at any of the U.S. licensed nuclear facilities and also to limit the liability of nuclear reactor owners for such claims from any single incident. As of June 30, 2015, the current liability limit per incident was $13.4 billion and is subject to change to account for the effects of inflation and changes in the number of licensed reactors. An inflation adjustment must be made at least once every 5 years and the last inflation adjustment was made effective September 10, 2013. In accordance with the Price-Anderson Act, Generation maintains financial protection at levels equal to the amount of liability insurance available from private sources through the purchase of private nuclear energy liability insurance for public liability claims that could arise in the event of an incident. As of June 30, 2015, the amount of nuclear energy liability insurance purchased is $375 million for each operating site. Additionally, the Price-Anderson Act requires a second layer of protection through the mandatory participation in a retrospective rating plan for power reactors (currently 102 reactors) resulting in an additional $12.9 billion in funds available for public liability claims. Participation in this secondary financial protection pool requires the operator of each reactor to fund its proportionate share of costs for any single incident that exceeds the primary layer of financial protection. Under the Price-Anderson Act, the maximum assessment in the event of an incident for each nuclear operator, per reactor, per incident (including a 5% surcharge), is $127.3 million, payable at no more than $19 million per reactor per incident per year. Exelon s maximum liability per incident is approximately $2.7 billion, including CENG s related liability.

In addition, the U.S. Congress could impose revenue-raising measures on the nuclear industry to pay public liability claims exceeding the $13.4 billion limit for a single incident.

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

NEIL provides all risk property damage, decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. If the decision is made to decommission the facility, a portion of the insurance proceeds will be allocated to a fund, which Generation is required by the NRC to maintain, to provide for decommissioning the facility. In the event of an insured loss, Generation is unable to predict the timing of the availability of insurance proceeds to Generation and the amount of such proceeds that would be available. In the event that one or more acts of terrorism cause accidental property damage within a twelve-month period from the first accidental property damage under one or more policies for all insured plants, the maximum recovery for all losses by all insureds will be an aggregate of $3.2 billion plus such additional amounts as the insurer may recover for all such losses from reinsurance, indemnity and any other source, applicable to such losses.

For its insured losses, Generation is self-insured to the extent that losses are within the policy deductible or exceed the amount of insurance maintained. Uninsured losses and other expenses, to the extent not recoverable from insurers or the nuclear industry, could also be borne by Generation. Any such losses could have a material adverse effect on Exelon s and Generation s financial condition, results of operations and liquidity.

Environmental Issues

General. The Registrants operations have in the past, and may in the future, require substantial expenditures in order to comply with environmental laws. Additionally, under Federal and state environmental laws, the Registrants are generally liable for the costs of remediating environmental contamination of property now or formerly owned by them and of property contaminated by hazardous substances generated by them. The Registrants own or lease a number of real estate parcels, including parcels on which their operations or the operations of others may have resulted in contamination by substances that are considered hazardous under environmental laws. In addition, the Registrants are currently involved in a number of proceedings relating to sites where hazardous substances have been deposited and may be subject to additional proceedings in the future.

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

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

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

121

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

BGE has identified 13 former gas manufacturing or purification sites that it currently owns or owned at one time through a predecessor s acquisition. Two gas manufacturing sites require some level of remediation and ongoing monitoring under the direction of the MDE. The required costs at these two sites are not considered material. An investigation of an additional gas purification site was completed during the first quarter of 2015 at the direction of the MDE. For more information, see the discussion of the Riverside site below.

ComEd, pursuant to an ICC order, and PECO, pursuant to settlements of natural gas distribution rate cases with the PAPUC, are currently recovering environmental remediation costs of former MGP facility sites through customer rates. ComEd and PECO have recorded regulatory assets for the recovery of these costs. See Note 5 Regulatory Matters for additional information regarding the associated regulatory assets. BGE is authorized to recover, and is currently recovering, environmental costs for the remediation of the former MGP facility sites from customers; however, while BGE does not have a rider for MGP clean-up costs, BGE has historically received recovery of actual clean-up costs in distribution rates. BGE has not established a regulatory asset for the costs associated with the gas purification site as of June 30, 2015.

As of June 30, 2015 and December 31, 2014, the Registrants had accrued the following undiscounted amounts for environmental liabilities in Other current liabilities and Other deferred credits and other liabilities within their respective Consolidated Balance Sheets:

June 30, 2015	Total Environmental Investigation and Remediation Reserve	Portion of Total Related to MGP Investigation and Remediation
Exelon	$ 337	$ 267
Generation	63	
ComEd	227	224
PECO	44	41
BGE	3	2

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

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

Water Quality

Groundwater Contamination. In October 2007, a subsidiary of Constellation entered into a consent decree with the MDE relating to groundwater contamination at a third-party facility that was licensed to accept fly ash, a byproduct generated by coal-fired plants. The consent decree required the payment of a $1 million penalty, remediation of groundwater contamination resulting from the ash placement operations at the site, replacement of drinking water supplies in the vicinity of the site, and monitoring of groundwater conditions. Generation s remaining groundwater contamination reserve was $13 million at both June 30, 2015 and December 31, 2014.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Air Quality

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

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

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

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

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

Generation increased its reserve for asbestos-related bodily injury claims pertaining to Midwest Generations share of liability as a result of the rejection of the asbestos cost sharing agreement in the bankruptcy proceedings. Exelon and Generation may be entitled to damages associated with the rejection of the agreement and a claim has been filed by Exelon for such damages. These amounts are considered to be contingent gains and would not be recognized until realized.

As a prior owner of the generating stations, ComEd (and Generation, through its agreement in Exelon s 2001 corporate restructuring to assume ComEd s rights and obligations associated with its former generation business) could face liability (along with any other potentially responsible parties) for environmental conditions at the stations requiring remediation, with the determination of the allocation among the parties subject to many uncertain factors. ComEd and Generation are unable to predict whether and to what extent they may ultimately be held responsible for remediation and other costs relating to the generating stations and as a result no liability has been recorded as of June 30, 2015. Any liability imposed on ComEd or Generation for environmental matters relating to the generating stations could have a material adverse impact on their future results of operations and cash flows.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Solid and Hazardous Waste

Cotter Corporation. The U.S. EPA has advised Cotter Corporation (Cotter), a former ComEd subsidiary, that it is potentially liable in connection with radiological contamination at a site known as the West Lake Landfill in Missouri. On February 18, 2000, ComEd sold Cotter to an unaffiliated third- party. As part of the sale, ComEd agreed to indemnify Cotter for any liability arising in connection with the West Lake Landfill. In connection with Exelon s 2001 corporate restructuring, this responsibility to indemnify Cotter was transferred to Generation. On May 29, 2008, the U.S. EPA issued a Record of Decision approving the remediation option submitted by Cotter and the two other PRPs that required additional landfill cover. By letter dated January 11, 2010, the U.S. EPA requested that the PRPs perform a supplemental feasibility study for a remediation alternative that would involve complete excavation of the radiological contamination. On September 30, 2011, the PRPs submitted the final supplemental feasibility study to the U.S. EPA for review. In June 2012, the U.S. EPA requested that the PRPs perform additional analysis and groundwater sampling as part of the supplemental feasibility study, and subsequently requested additional analysis sampling and modeling that will be conducted throughout 2015. In light of these additional requests, it is unknown when the U.S EPA will propose a remedy for public comment, but will likely be sometime in 2017 at the earliest. Thereafter the U.S. EPA will select a final remedy and enter into a Consent Decree with the PRPs to effectuate the remedy. A complete excavation remedy would be significantly more expensive than the previously selected additional cover remedy; however, Generation believes the likelihood that the U.S. EPA would require a complete excavation remedy is remote. The current estimated cost of the landfill cover remediation for the site is approximately $60 million, which will be allocated among all PRPs. Generation has accrued what it believes to be an adequate amount to cover its anticipated share of such liability.

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

On February 28, 2012, and April 10, 2012, two lawsuits were filed in the U.S. District Court for the Eastern District of Missouri against 13 and 16 defendants, respectively, including Exelon, Generation and ComEd (the Exelon defendants) and Cotter. The suits allege that individuals living in the North St. Louis area developed some form of cancer due to the Exelon defendants negligent or reckless conduct in processing, transporting, storing, handling and/or disposing of radioactive materials. Plaintiffs have asserted claims for negligence, strict liability, emotional distress, medical monitoring, and violations of the Price-Anderson Act. The complaints do not contain specific damage claims. On May 30, 2012, the plaintiffs filed voluntary motions to dismiss the Exelon defendants from both lawsuits which were subsequently granted. Since May 30, 2012, several related lawsuits have been filed in the same court on behalf of various plaintiffs against Cotter and other defendants, but not Exelon. The allegations in these related lawsuits mirror the initially filed lawsuits. In the event of a finding of liability, it is reasonably possible that Exelon would be considered liable due to its indemnification responsibilities of Cotter described above. On March 27, 2013, the U.S. District Court dismissed all state

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

common law actions brought under the initial two lawsuits; and also found that the plaintiffs had not properly brought the actions under the Price-Anderson Act. On July 8, 2013, the plaintiffs filed amended complaints under the Price-Anderson Act. Cotter moved to dismiss the amended complaints and has motions currently pending before the court. At this stage of the litigation, Exelon, Generation, and ComEd cannot estimate a range of loss, if any.

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

Rossville Ash Site. The Rossville Ash Site is a 32-acre property located in Rosedale, Baltimore County, Maryland, which was used for the placement of fly ash from 1983-2007. The property is owned by Constellation Power Source Generation, LLC (CPSG). In 2008, CPSG investigated and remediated the property by entering it into the Maryland Voluntary Cleanup Program (VCP) to address any historic environmental concerns and ready the site for appropriate future redevelopment. The site was accepted into the program in 2010 and is currently going through the process to remediate the site and receive closure from MDE. Exelon currently estimates the cost to close the site to be approximately $9 million, which has been fully reserved as of June 30, 2015.

Sauer Dump. On May 30, 2012, BGE was notified by the U.S. EPA that it is considered a PRP at the Sauer Dump Superfund site in Dundalk, Maryland. The U.S. EPA offered BGE and three other PRPs the opportunity to conduct an environmental investigation and present cleanup recommendations at the site. In addition, the U.S. EPA is seeking recovery from the PRPs of $1.7 million for past cleanup and investigation costs at the site. On March 11, 2013, BGE and three other PRP s signed an Administrative Settlement Agreement and Order on Consent with the U.S. EPA which requires the PRP s to conduct a Remedial Investigation and Feasibility Study at the site to determine what, if any, are the appropriate and recommended cleanup activities for the site. The ultimate outcome of this proceeding is uncertain. Since the U.S. EPA has not selected a cleanup remedy and the allocation of the cleanup costs among the PRPs has not been determined, an estimate of the range of BGE s reasonably possible loss, if any, cannot be determined.

***Riverside*.** In 2013, the Maryland Department of the Environment (MDE), at the request of U.S. EPA, conducted a site inspection and limited environmental sampling of certain portions of the 170 acre Riverside property owned by BGE. The site consists of several different parcels with different current and historical uses. The sampling included soil and groundwater samples for a number of potential environmental contaminants. The sampling confirmed the existence of contaminants consistent with the known historical uses of the various portions of the site. In March 2014, the MDE requested that BGE conduct an investigation of three specific areas of the site, and a site-wide investigation of soils, sediment, groundwater, and surface water to complement the MDE sampling. The field investigation was completed in January 2015, and a final report was provided to MDE

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

on June 2, 2015. Upon completion of the investigation the MDE will determine if the site requires further action and/or remediation. Based upon the investigation to date, BGE has established what it believes is an appropriate reserve. As the investigation and potential remediation proceed, it is possible that additional reserves could be established, in amounts that would be material to BGE.

Litigation and Regulatory Matters

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

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

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

At June 30, 2015 and December 31, 2014, Generation had reserved approximately $97 million and $100 million, respectively, in total for asbestos-related bodily injury claims. As of June 30, 2015, approximately $20 million of this amount related to 213 open claims presented to Generation, while the remaining $77 million of the reserve is for estimated future asbestos-related bodily injury claims anticipated to arise through 2050, based on actuarial assumptions and analyses, which are updated on an annual basis. On a quarterly basis, Generation monitors actual experience against the number of forecasted claims to be received and expected claim payments and evaluates whether an adjustment to the reserve is necessary. During the second quarter of 2015, Generation increased its reserve by approximately $1 million, primarily due to an increase in actual and projected claims costs.

On November 22, 2013, the Supreme Court of Pennsylvania held that the Pennsylvania Workers Compensation Act does not apply to an employee s disability or death resulting from occupational disease, such as diseases related to asbestos exposure, which manifests more than 300 weeks after the employee s last employment-based exposure, and that therefore the exclusivity provision of the Act does not preclude such employee from suing his or her employer in court. The Supreme Court s ruling reverses previous rulings by the Pennsylvania Superior Court precluding current and former employees from suing their employers in court, despite the fact that the same employee was not eligible for workers compensation benefits for diseases that manifest more than 300 weeks after the employee s last employment-based exposure to asbestos. Since the Pennsylvania Supreme Court s ruling in November 2013 , Exelon, Generation, and PECO have experienced an increase in asbestos-related personal injury claims brought by former PECO employees, all of which have been reserved against on a claim by claim basis. Those additional claims are taken into account in projecting estimated future asbestos-related bodily injury claims.

On June 27, 2014, the Illinois Court of Appeals ruled that the Illinois Worker s Compensation law should not apply in cases where the diagnosis of an asbestos related disease occurred after the 25-year maximum time period for filing a Worker s Compensation claim. This decision is now on appeal to the Illinois Supreme Court. If confirmed on appeal, former employees could file suit against Exelon, Generation, and ComEd, similar to the way former employees are filing suit against Exelon in Pennsylvania. Currently, Exelon, Generation, and ComEd are unable to predict whether and to what extent they may experience additional claims in the future as a result of this ruling; as such, no increase to the asbestos-related bodily injury liability has been recorded as of June 30, 2015.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Approximately 468 individuals who were never employees of BGE or certain Constellation subsidiaries have pending claims each seeking several million dollars in compensatory and punitive damages. Cross-claims and third-party claims brought by other defendants may also be filed against BGE and certain Constellation subsidiaries in these actions. To date, most asbestos claims which have been resolved have been dismissed or resolved without any payment by BGE or certain Constellation subsidiaries and a small minority of these cases has been resolved for amounts that were not material to BGE or Generation s financial results.

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

- the identity of the facilities at which the plaintiffs allegedly worked as contractors;
- the names of the plaintiffs employers;
- the dates on which and the places where the exposure allegedly occurred; and
- the facts and circumstances relating to the alleged exposure.

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

Continuous Power Interruption (ComEd)

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

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

On June 5, 2013, the ICC approved a complete waiver of liability for five of the six summer storms and the February 2011 blizzard. The ICC held that for the July 11, 2011 storm, 34,559 interruptions were preventable and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

therefore no waiver should apply. As required by the ICC s Order, ComEd notified relevant customers that they may be entitled to seek reimbursement of incurred costs in accordance with a claims procedure established under ICC rules and regulations. On July 31, 2014, the Illinois Appellate Court reaffirmed the ICC s decision in ComEd s appeal of the Summer 2011 Storm Docket and dismissed ComEd s appeal of the February 2011 Blizzard Docket. The Illinois Supreme Court denied ComEd s request to hear the matter. The ICC s order is now final and claims from impacted customers and municipalities are now eligible for review and reimbursement. ComEd is processing claims received to date.

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

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

Telephone Consumer Protection Act Lawsuit (ComEd)

On November 19, 2013, a class action complaint was filed in the Northern District of Illinois on behalf of a single individual and a presumptive class that would include all customers that ComEd enrolled in its Outage Alert text message program. The complaint alleges that ComEd violated the Telephone Consumer Protection Act (TCPA) by sending approximately 1.2 million text messages to customers without first obtaining their consent to receive such messages. The complaint seeks certification of a class along with statutory damages, attorneys fees, and an order prohibiting ComEd from sending additional text messages. Such statutory damages could range from $500 to $1,500 per text. In February 2014, ComEd filed a motion to dismiss this class action complaint, which was denied in June 2014. On February 19, 2015, ComEd and the plaintiff agreed in principle to settle the suit for $5 million, which ComEd has recorded as a liability as of June 30, 2015. On June 8, 2015, the court granted preliminary approval of the settlement. A final approval hearing will be held in the fall of 2015. As ComEd is unable to predict the ultimate outcome of this proceeding, actual damages may differ from the estimated amount recorded, which may be material to ComEd s results of operations, cash flows, and financial position.

Baltimore City Franchise Taxes (BGE)

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

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

The Registrants are involved in various other litigation matters that are being defended and handled in the ordinary course of business. The assessment of whether a loss is probable or a reasonable possibility, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. The Registrants maintain accruals for such losses that are probable of being incurred and subject to reasonable

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

estimation. Management is sometimes unable to estimate an amount or range of reasonably possible loss, particularly where (1) the damages sought are indeterminate, (2) the proceedings are in the early stages, or (3) the matters involve novel or unsettled legal theories. In such cases, there is considerable uncertainty regarding the timing or ultimate resolution of such matters, including a possible eventual loss.

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

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

20. Supplemental Financial Information (Exelon, Generation, ComEd, PECO and BGE)

Supplemental Statement of Operations Information

The following tables provide additional information about the Registrants Consolidated Statements of Operations and Comprehensive Income for the three and six months ended June 30, 2015 and 2014:

Three Months Ended June 30, 2015	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 93	$ 93	$	$	$
Non-regulatory agreement units	74	74			
Net unrealized losses on decommissioning trust funds					
Regulatory agreement units	(133)	(133)			
Non-regulatory agreement units	(96)	(96)			
Regulatory offset to decommissioning trust fund-related activities[b]	28	28			
Total decommissioning-related activities	(34)	(34)			
Investment income (expense)	1			(1)	1[c]
Long-term lease income	4				
AFUDC Equity	5		1	1	3
Other	7	3	4	1	
Other, net	$ (17)	$ (31)	$ 5	$ 1	$ 4

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 164	$ 164	$	$	$
Non-regulatory agreement units	104	104			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	(85)	(85)			
Non-regulatory agreement units	(56)	(56)			
Net unrealized gains on pledged assets					
Zion Station decommissioning	9	9			
Regulatory offset to decommissioning trust fund-related activities[b]	(78)	(78)			
Total decommissioning-related activities	58	58			
Investment income (expense)	4	1		(1)	2[c]
Long-term lease income	8				
Interest income related to uncertain income tax positions		1			
AFUDC Equity	11		1	3	7
Terminated interest rate swaps[d]	(26)				
Other	9	2	8	1	(1)
Other, net	$ 64	$ 62	$ 9	$ 3	$ 8

Three Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[a]					
Regulatory agreement units	$ 68	$ 68	$	$	$
Non-regulatory agreement units	38	38			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	172	172			
Non-regulatory agreement units	128	128			
Net unrealized losses on pledged assets					
Zion Station decommissioning	10	10			
Regulatory offset to decommissioning trust fund-related activities[b]	(204)	(204)			
Total decommissioning-related activities	212	212			
Investment income (expense)	7	7		(1)	2[c]
Long-term lease income	10				
Interest income related to uncertain income tax positions	(2)	3			
AFUDC Equity	4			1	3
Other	(1)	(6)	5	1	
Other, net	$ 230	$ 216	$ 5	$ 1	$ 5

130

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other, Net					
Decommissioning-related activities:					
Net realized income on decommissioning trust funds[(a)]					
Regulatory agreement units	$ 111	$ 111	$	$	$
Non-regulatory agreement units	63	63			
Net unrealized gains on decommissioning trust funds					
Regulatory agreement units	234	234			
Non-regulatory agreement units	141	141			
Net unrealized losses on pledged assets					
Zion Station decommissioning	20	20			
Regulatory offset to decommissioning trust fund-related activities[(b)]	(299)	(299)			
Total decommissioning-related activities	270	270			
Investment income (expense)	8	8		(1)	4[(c)]
Long-term lease income	17				
Interest income related to uncertain income tax positions	7	17			
AFUDC Equity	12		3	3	6
Other	16	5	7	1	(1)
Other, net	$ 330	$ 300	$ 10	$ 3	$ 9

(a) Includes investment income and realized gains and losses on sales of investments of the trust funds.
(b) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of net income taxes related to all NDT fund activity for those units. See Note 15 Asset Retirement Obligations of the Exelon 2014 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(c) Relates to the cash return on BGE s rate stabilization deferral. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information regarding the rate stabilization deferral.
(d) In January 2015, in connection with Generation s $750 million issuance of five-year Senior Unsecured Notes, Exelon terminated certain floating-to-fixed interest rate swaps. As the original forecasted transactions were a series of future interest payments over a ten year period, a portion of the anticipated interest payments are probable not to occur. As a result, $26 million of anticipated payments were reclassified from Accumulated OCI to Other, net in Exelon s Consolidated Statement of Operations and Comprehensive Income.

Supplemental Cash Flow Information

The following tables provide additional information regarding the Registrants Consolidated Statements of Cash Flows for the six months ended June 30, 2015 and 2014:

Six Months Ended June 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,087	$ 485	$ 312	$ 119	$ 143
Regulatory assets	101		40	12	49
Amortization of intangible assets, net	24	24			
Amortization of energy contract assets and liabilities[(a)]		1			
Nuclear fuel[(b)]	552	552			

ARO accretion[c]	193	193			
Total depreciation, amortization, accretion and depletion	$ 1,957	$ 1,255	$ 352	$ 131	$ 192

131

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Depreciation, amortization, accretion and depletion					
Property, plant and equipment	$ 1,015	$ 444	$ 290	$ 112	$ 142
Regulatory assets	117		57	5	55
Amortization of intangible assets, net	22	22			
Amortization of energy contract assets and liabilities[(a)]	113	118			
Nuclear fuel[(b)]	499	499			
ARO accretion[(c)]	159	159			
Total depreciation, amortization, accretion and depletion	$ 1,925	$ 1,242	$ 347	$ 117	$ 197

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

Six Months Ended June 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 317	$ 133	$ 103	$ 19	$ 33
Loss from equity method investments	2	3			
Provision for uncollectible accounts	80	11	35	24	11
Stock-based compensation costs	79				
Other decommissioning-related activity[(a)]	(50)	(50)			
Energy-related options[(b)]	27	27			
Amortization of regulatory asset related to debt costs					
Amortization of rate stabilization deferral	40				40
Amortization of debt fair value adjustment	(37)	(6)			
Discrete impacts of EIMA[(c)]	77		77		
Amortization of debt costs	35	8	2	1	1
Lower of cost or market inventory adjustment	13	13			
Other	(4)	(5)	5	1	(9)
Total other non-cash operating activities	$ 579	$ 134	$ 222	$ 45	$ 76
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 45	$	$ 10	$ 27	$ 8
Other regulatory assets and liabilities	47		26	(13)	(18)
Cash deposits[(d)]	242	242			
Other current assets	(53)	(39)	3	(74)[(e)]	60
Other noncurrent assets and liabilities	(67)		(14)		1
Total changes in other assets and liabilities	$ 214	$ 203	$ 25	$ (60)	$ 51
Non-cash investing and financing activities:					
Indemnification of like-kind exchange position[(f)]	$	$	$ 3	$	$
Long-term software licensing agreement[(g)]	95				

Total non-cash investing and financing activities:	$ 95	$	$ 3	$	$

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Six Months Ended June 30, 2014	Exelon	Generation	ComEd	PECO	BGE
Other non-cash operating activities:					
Pension and non-pension postretirement benefit costs	$ 315	$ 139	$ 96	$ 21	$ 33
Equity method investments	20	20			
Provision for uncollectible accounts	59	8	(8)	28	30
Stock-based compensation costs	68				
Other decommissioning-related activity[(a)]	(85)	(85)			
Energy-related options[(b)]	63	63			
Amortization of rate stabilization deferral	33				33
Amortization of debt fair value adjustment	(26)	(12)			
Discrete impacts from EIMA[(c)]	9		9		
Amortization of debt costs	19	6	(3)	1	1
Other	(2)		5		(8)
Total other non-cash operating activities	$ 473	$ 139	$ 99	$ 50	$ 89
Changes in other assets and liabilities:					
Under/over-recovered energy and transmission costs	$ 60	$	$ 61	$ (6)	$ 8
Other regulatory assets and liabilities	(25)		(30)	(13)	(49)
Other current assets	(157)	13	(5)	(89)[(e)]	51
Other noncurrent assets and liabilities	(158)	(69)	22	(6)	(2)
Total changes in other assets and liabilities	$ (280)	$ (56)	$ 48	$ (114)	$ 8
Non-cash investing and financing activities:					
Fair value of net assets recorded upon CENG consolidation	$ 3,400	$ 3,400	$	$	$
Issuance of equity units	131				
Uranium procurement	38	38			
Indemnification of like-kind exchange position[(f)]			2		
Total non-cash investing and financing activities	$ 3,569	$ 3,438	$ 2	$	$

(a) Includes the elimination of NDT fund activity for the Regulatory Agreement Units, including the elimination of operating revenues, ARO accretion, ARC amortization, investment income and income taxes related to all NDT fund activity for these units. See Note 15 Asset Retirement Obligations of the Exelon 2014 Form 10-K for additional information regarding the accounting for nuclear decommissioning.
(b) Includes option premiums reclassified to realized at the settlement of the underlying contracts and recorded to results of operations.
(c) Reflects the change in distribution rates pursuant to EIMA, which allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff. See Note 5 Regulatory Matters for more information.
(d) Relates primarily to cash deposits recalled from ISOs/RTOs and replaced with letters of credit.
(e) Relates primarily to prepaid utility taxes.
(f) See Note 12 Income Taxes for discussion of the like-kind exchange tax position.
(g) Relates to a long-term software license agreement entered into on May 31, 2015. Exelon is required to make payments starting August of 2015 through May of 2024. See Note 11 Debt and Credit Agreements for additional information.

DOE Smart Grid Investment Grant (Exelon and PECO). For the six months ended June 30, 2014, PECO has included in the capital expenditures line item under investing activities of the cash flow statement capital expenditures of $2 million and reimbursements of $3 million related to PECO s DOE SGIG programs. For the six months ended June 30, 2015 PECO had no capital expenditures or reimbursements, as the DOE SGIG program was completed during 2014. See Note 3 Regulatory Matters of the Exelon 2014 Form 10-K for additional information regarding the DOE SGIG.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Supplemental Balance Sheet Information

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

June 30, 2015	Exelon	Generation	ComEd	PECO	BGE
Property, plant and equipment:					
Accumulated depreciation and amortization	$ 15,553[(a)]	$ 8,146[(a)]	$ 3,571	$ 3,028	$ 2,928
Accounts receivable:					
Allowance for uncollectible accounts	323[(c)]	67	95	101[(c)]	60

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

(a) Includes accumulated amortization of nuclear fuel in the reactor core of $2,804 million.
(b) Includes accumulated amortization of nuclear fuel in the reactor core of $2,673 million.
(c) Includes an allowance for uncollectible accounts of $9 million and $7 million at June 30, 2015 and December 31, 2014, respectively, related to PECO s current installment plan receivables described below.

PECO Installment Plan Receivables (Exelon and PECO)

PECO enters into payment agreements with certain delinquent customers, primarily residential, seeking to restore their service, as required by the PAPUC. Customers with past due balances that meet certain income criteria are provided the option to enter into an installment payment plan, some of which have terms greater than one year, to repay past due balances in addition to paying for their ongoing service on a current basis. The receivable balance for these payment agreement receivables is recorded in accounts receivable for the current portion and other deferred debits and other assets for the noncurrent portion. The net receivable balance for installment plans with terms greater than one year was $16 million and $15 million as of June 30, 2015 and December 31, 2014, respectively. The allowance for uncollectible accounts reserve methodology and assessment of the credit quality of the installment plan receivables are consistent with the customer accounts receivable methodology discussed in Note 1 Significant Accounting Policies of the Exelon 2014 Form 10-K. The allowance for uncollectible accounts balance associated with these receivables at June 30, 2015 of $18 million consists of $1 million, $4 million and $13 million for low risk, medium risk and high risk segments, respectively. The allowance for uncollectible accounts balance at December 31, 2014 of $15 million consists of $1 million, $3 million and $11 million for low risk, medium risk and high risk segments, respectively. The balance of the payment agreement is billed to the customer in equal monthly installments over the term of the agreement. Installment receivables outstanding as of June 30, 2015 and December 31, 2014 include balances not yet presented on the customer bill, accounts currently billed and an immaterial amount of past due receivables. When a customer defaults on its payment agreement, the terms of which are defined by plan type, the entire balance of the agreement becomes due and the balance is reclassified to current customer accounts receivable and reserved for in accordance with the methodology discussed in Note 1 Significant Accounting Policies of the Exelon 2014 Form 10-K.

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

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

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Exelon has nine reportable segments, ComEd, PECO, BGE and Generation s six power marketing reportable segments consisting of the Mid-Atlantic, Midwest, New England, New York, ERCOT and all other power regions referred to collectively as Other Power Regions ; which includes activities in the South, West and Canada. ComEd, PECO and BGE each represent a single reportable segment; as such, no separate segment information is provided for these Registrants. Exelon, ComEd, PECO and BGE s CODMs evaluate the performance of and allocate resources to ComEd, PECO and BGE based on net income and return on equity.

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

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

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

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

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

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

Other Power Regions:

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

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

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

The CODMs for Exelon and Generation evaluate the performance of Generation s power marketing activities and allocate resources based on revenue net of purchased power and fuel expense. Generation believes that revenue net of purchased power and fuel expense is a useful measurement of operational performance. Revenue net of purchased power and fuel expense (RNF) is not a presentation defined under GAAP and may not be comparable to other companies presentations or deemed more useful than the GAAP information provided

Table of Contents

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

elsewhere in this report. Generation s operating revenues include all sales to third parties and affiliated sales to ComEd, PECO, and BGE. Purchased power costs include all costs associated with the procurement and supply of electricity including capacity, energy and ancillary services. Fuel expense includes the fuel costs for Generation s owned generation and fuel costs associated with tolling agreements. Generation s other business activities, including retail and wholesale gas, investments in gas and oil exploration and production activities, proprietary trading, compressed natural gas fueling stations, energy efficiency and cogeneration projects, sales of electric and gas appliances, servicing of heating, air conditioning, plumbing, electrical, indoor quality systems and home improvements, and investments in energy-related proprietary technology are not allocated to regions. Further, Generation s unrealized mark-to-market impact of economic hedging activities, amortization of certain intangible assets relating to commodity contracts recorded at fair value from mergers and acquisitions and other miscellaneous revenues are also not allocated to a region. Exelon and Generation do not use a measure of total assets in making decisions regarding allocating resources to or assessing the performance of these reportable segments.

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

Three Months Ended June 30, 2015 and 2014

	Generation[a]	ComEd	PECO	BGE	Other[b]	Intersegment Eliminations	Exelon
Total revenues[c]:							
2015	$ 4,232	$ 1,148	$ 661	$ 628	$ 340	$ (495)	$ 6,514
2014	3,789	1,128	656	653	329	(531)	6,024
Intersegment revenues[d]:							
2015	$ 152	$ 1	$	$ 1	$ 340	$ (493)	$ 1
2014	201			2	328	(531)	
Net income (loss):							
2015	$ 390	$ 99	$ 70	$ 47	$ 28	$ (1)	$ 633
2014	372	111					