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

Washington, D.C. 20549

FORM 10-Q

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

For the Quarterly Period Ended March 31, 2015

or

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

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 March 31, 2015 was:

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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Exelon Corporation and Related Entities

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

Other Terms and Abbreviations

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

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations

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

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FILING FORMAT

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

FORWARD-LOOKING STATEMENTS

This Report contains certain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995 that are subject to risks and uncertainties. The factors that could cause actual results to differ materially from the forward-looking statements made by the Registrants include those factors discussed herein, as well as the items discussed in (1) Exelon s 2014 Annual Report on Form 10-K in (a) ITEM 1A. Risk Factors, (b) ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) ITEM 8. Financial Statements and Supplementary Data: Note 22; (2) this Quarterly Report on Form 10-Q in (a) Part II, Other Information, ITEM 1A. Risk Factors, (b) Part 1, Financial Information, ITEM 2. Management s Discussion and Analysis of Financial Condition and Results of Operations and (c) Part I, Financial Information, ITEM 1. Financial Statements: Note 17; and (3) other factors discussed in filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

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

Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

Total liabilities and shareholders equity	$ 87,391	$ 86,814

(a) Exelon s consolidated assets include $8,182 million and $8,160 million at March 31, 2015 and December 31, 2014, respectively, of certain VIEs that can only be used to settle the liabilities of the VIE. Exelon s consolidated liabilities include $2,702 million and $2,723 million at March 31, 2015 and December 31, 2014, respectively, of certain VIEs for which the VIE creditors do not have recourse to Exelon. See Note 3 Variable Interest Entities.

See the Combined Notes to Consolidated Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

Other comprehensive loss	(17)	(21)
Comprehensive income (loss)	$ 468	$ (206)

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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

See the Combined Notes to Consolidated Financial Statements

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(Unaudited)

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

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

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

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDER S EQUITY

(Unaudited)

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

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

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

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

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

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

See the Combined Notes to Consolidated Financial Statements

BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(Unaudited)

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

(a) BGE s consolidated assets include $49 million and $24 million at March 31, 2015 and December 31, 2014, respectively, of BGE s consolidated VIE that can only be used to settle the liabilities of the VIE. BGE s consolidated liabilities include $200 million and $197 million at March 31, 2015 and December 31, 2014, respectively, of BGE s consolidated VIE for which the VIE creditors do not have recourse to BGE. See Note 3 Variable Interest Entities.

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

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

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

The energy generation business includes:

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

The energy delivery businesses include:

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

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

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

Each of the Registrant s consolidated financial statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated. As a result of the 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 will be presented below Income taxes in the Registrants Statement of Operations and Comprehensive Income starting in the first quarter of 2015. For the three months ended March 31, 2015, Equity in earnings (losses) of unconsolidated affiliates was less than $1 million.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

Customer s Accounting for Fees Paid in a Cloud Computing Arrangement

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

Simplifying the Presentation of Debt Issuance Costs

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

Amendments to the Consolidation Analysis

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

Revenue from Contracts with Customers

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Consolidated Variable Interest Entities

Exelon, Generation and BGE s consolidated VIEs consist of:

- BondCo, a special purpose bankruptcy remote limited liability company formed by BGE to acquire, hold, issue and service bonds secured by rate stabilization property,
- a retail gas group formed by Generation to enter into a collateralized gas supply agreement with a third-party gas supplier
- a group of solar project limited liability companies formed by Generation to build, own and operate solar power facilities,
- several wind project companies designed by Generation to develop, construct and operate wind generation facilities,
- certain retail power companies for which Generation is the sole supplier of energy, and

CENG.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

Generation executed an Indemnity Agreement pursuant to which Generation agreed to indemnify EDF and its affiliates against third-party claims that may arise from any future nuclear incident (as defined in the Price-Anderson Act) in connection with the CENG nuclear plants or their operations. Exelon guarantees Generation s obligations under this Indemnity Agreement. (See Note 17 Commitments and Contingencies for more details), in connection with CENG s severance obligations, Generation has agreed to reimburse CENG for a total of approximately $6 million of the severance benefits paid or to be paid in 2014 through 2016. As of March 31, 2015, the remaining obligation is approximately $2 million,

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Generation provides a $75 million parental guarantee to the third-party gas supplier in support of its retail gas group.

For each of the consolidated VIEs, except as otherwise noted:

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

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

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

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

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Assets and Liabilities of Consolidated VIEs

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

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

Total liabilities	$ 2,702	$ 2,486	$ 200	$ 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 12 Retirement Benefits for additional details.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Unconsolidated Variable Interest Entities

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

The Registrants unconsolidated VIEs consist of:

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

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

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

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

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

December 31, 2014	**Commercial Agreement VIEs**	**Equity Investment VIEs**	**Total**
Total assets[(a)]	$ 506	$ 91	$ 597

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

4. Mergers, Acquisitions, and Dispositions

Proposed Merger with Pepco Holdings, Inc. (Exelon)

Description of Transaction

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

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

To date, the PHI stockholders, the Virginia State Corporation Commission, the New Jersey Board of Public Utilities (NJBPU) 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.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

Merger Financing

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

Acquisitions (Exelon and Generation)

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

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

Asset Divestitures (Exelon and Generation)

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

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

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 March 31, 2015, and December 31, 2014, ComEd had recorded a net regulatory asset associated with the distribution formula rate of $316 million and $371 million, respectively. The regulatory asset associated with distribution true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Pennsylvania Regulatory Matters

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

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

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

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

On March 12, 2015, PECO settled the CAP Design with the Office of Consumer Advocates (OCA) and Low Income Advocates, and filed the proposed plan with the PAPUC on March 20, 2015. The program design changes the rate structure of PECO s CAP to make the bills more affordable to customers enrolled in the assistance program. The CAP discounts continue to be recovered through PECO s universal service fund cost. If the CAP Design proposed plan is approved by the PAPUC, PECO plans to implement the program changes in October 2016.

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

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

Pennsylvania Act 11 of 2012 (Exelon and PECO). In February 2012, Act 11 was signed into law, which seeks to clarify the PAPUC s authority to approve alternative ratemaking mechanisms, allowing for the implementation of a distribution system improvement charge (DSIC) in rates designed to recover capital project costs incurred to repair, improve or replace utilities aging electric and natural gas distribution systems in Pennsylvania. Prior to recovering costs pursuant to a DSIC, the PAPUC s implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) approved by the Commission, which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure.

On February 5, 2015, PECO filed a petition to modify its natural gas LTIIP with the PAPUC, which was originally approved by the PAPUC in May 2013. If approved, the modification would allow PECO to further accelerate the replacement of existing gas mains and also included a plan for the relocation of meters from indoors to outside in accordance with recent PAPUC rulemaking. In addition, on March 20, 2015, PECO filed a petition with the PAPUC for approval of its gas DSIC mechanism for recovery of gas 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 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 recovered through a grant from the DOE. The MDPSC s approval ordered BGE to defer the associated incremental costs, depreciation and amortization, and an appropriate return, in a regulatory asset until such time as a cost-effective advanced metering system is implemented. As of March 31, 2015 and December 31, 2014, BGE recorded a regulatory asset of $143 million and $128 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program. As part of the settlement in BGE s 2014 electric and gas distribution rate case, the cost of the retired non-AMI meters will be amortized over 10 years.

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

New York Regulatory Matters

Ginna Nuclear Power Plant Reliability Support Services Agreement (Exelon and Generation). Ginna Nuclear Power Plant s (Ginna) prior period fixed-price PPA contract with Rochester Gas & Electric Company (RG&E) expired in June 2014. In light of the expiration of the agreement, Ginna advised the New York Public Service Commission (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. 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 March 31, 2015 and December 31, 2014, ComEd had recorded a net regulatory asset associated with the transmission formula rate of $25 million and $21 million, respectively, and BGE recorded a net regulatory asset associated with the transmission formula rate of $2 million and $1 million at March 31, 2015 and December 31, 2014, respectively. The regulatory asset associated with the transmission true-up is amortized to Operating revenues as the associated amounts are recovered through rates.

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

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

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

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

Exelon, ComEd, PECO and BGE each prepare their consolidated financial statements in accordance with the authoritative guidance for accounting for certain types of regulation. Under this guidance, regulatory assets represent incurred costs that have been deferred because of their probable future recovery from customers through regulated rates. Regulatory liabilities represent the excess recovery of costs or accrued credits that have been deferred because it is probable such amounts will be returned to customers through future regulated rates or represent billings in advance of expenditures for approved regulatory programs.

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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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 March 31, 2015, ComEd s regulatory asset of $316 million was comprised of $240 million for the applicable annual reconciliations and $76 million related to significant one-time events including $59 million of deferred storm costs and $17 million of Constellation merger and integration related costs. As of December 31, 2014, ComEd s regulatory asset of $371 million was comprised of $286 million for the applicable annual reconciliations and $85 million related to significant one-time events, including $66 million of deferred storm costs and $19 million of Constellation merger and integration related costs. See Note 4 Mergers, Acquisitions, and Dispositions of the Exelon 2014 Form 10-K for further information.

(b) As of March 31, 2015, ComEd s regulatory asset of $37 million included $5 million related to under-recovered energy costs for non-hourly customers, $25 million associated with transmission costs recoverable through its FERC approved formulate rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of March 31, 2015, ComEd s regulatory liability of $23 million included $5 million related to over-recovered energy costs for hourly customers and $18 million associated with revenues received for renewable energy requirements. As of December 31, 2014, ComEd s regulatory asset of $33 million included $4 million related to under-recovered energy costs for non-hourly customers, $22 million associated with transmission costs recoverable through its FERC approved formulate rate, and $7 million of Constellation merger and integration costs to be recovered upon FERC approval. As of December 31, 2014, ComEd s regulatory liability of $19 million included $3 million related to over-recovered energy costs for hourly customers and $16 million associated with revenues received for renewable energy requirements.

(c) As of March 31, 2015, BGE s regulatory asset of $4 million included $4 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval, partially offset by $1 million related to over-recovered electric energy costs. As of March 31, 2015, BGE s regulatory liability of $35 million related to $31 million of over-recovered natural gas supply costs and $4 million of over-recovered electric energy costs. As of December 31, 2014, BGE s regulatory asset of $15 million included $10 million related to under-recovered electric energy costs, $4 million of Constellation merger and integration costs and $1 million of abandonment costs to be recovered upon FERC approval. As of December 31, 2014, BGE s regulatory liability of $7 million related to over-recovered natural gas supply costs.

(d) At PECO, includes $42 million related to the DSP program, $34 million related to the over-recovered natural gas costs under the PGC and $8 million related to over-recovered electric transmission costs as of March 31, 2015. As of December 31, 2014, includes $39 million related to the DSP program, $16 million related to the over-recovered electric transmission costs and $3 million related to the over-recovered natural gas costs under the PGC.

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

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

Purchase of Receivables Programs (Exelon, ComEd, PECO, and BGE)

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

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

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 (PORCB) tariff.

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Accounting for the Consolidation of CENG

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

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

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

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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

7. Fair Value of Financial Assets and Liabilities (Exelon, Generation, ComEd, PECO and BGE)

Fair Value of Financial Liabilities Recorded at the Carrying Amount

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

Exelon

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

	December 31, 2014				
	Carrying	Fair Value			
	Amount	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

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

	December 31, 2014				
	Carrying	Fair Value			
	Amount	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

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

		December 31, 2014			
	Carrying	Fair Value			
	Amount	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

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

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

BGE

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

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

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

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Recurring Fair Value Measurements

Exelon records the fair value of assets and liabilities in accordance with the hierarchy established by the authoritative guidance for fair value measurements. The hierarchy prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

Level 1 quoted prices (unadjusted) in active markets for identical assets or liabilities that the Registrants have the ability to access as of the reporting date.

Level 2 inputs other than quoted prices included within Level 1 that are directly observable for the asset or liability or indirectly observable through corroboration with observable market data.

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

Transfers in and out of levels are recognized as of the end of the reporting period when the transfer occurred. Given derivatives categorized within Level 1 are valued using exchange-based quoted prices within observable periods, transfers between Level 2 and Level 1 were not material. Transfers into Level 2 from Level 3 generally occur when the contract tenure becomes more observable. Transfers into Level 3 from Level 2 generally occur due to changes in market liquidity or assumptions for certain commodity contracts. There were

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Exelon and Generation

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

	Generation				Exelon			
As of March 31, 2015	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets								
Cash equivalents[(a)]	$ 220	$	$	$ 220	$ 1,107	$	$	$ 1,107
Nuclear decommissioning trust fund investments								
Cash equivalents	224	40		264	224	40		264
Equity								
Domestic	2,459	2,227		4,686	2,459	2,227		4,686
Foreign	639			639	639			639
Equity funds subtotal	3,098	2,227		5,325	3,098	2,227		5,325
Fixed income								
Corporate debt		1,911	248	2,159		1,911	248	2,159
U.S. Treasury and agencies	1,201			1,201	1,201			1,201
Foreign governments		89		89		89		89
State and municipal debt		423		423		423		423
Other		488		488		488		488
Fixed income subtotal	1,201	2,911	248	4,360	1,201	2,911	248	4,360
Middle market lending			363	363			363	363
Private Equity			95	95			95	95
Real Estate			9	9			9	9
Other		323		323		323		323
Nuclear decommissioning trust fund investments subtotal[(b)]	4,523	5,501	715	10,739	4,523	5,501	715	10,739
Pledged assets for Zion Station decommissioning								
Cash equivalents		19		19		19		19
Equities	6	1		7	6	1		7
Fixed income								
U.S. Treasury and agencies	2	3		5	2	3		5
Corporate debt		84		84		84		84
State and municipal debt		10		10		10		10
Other		4		4		4		4
Fixed income subtotal	2	101		103	2	101		103
Middle market lending			178	178			178	178
Pledged assets for Zion Station decommissioning subtotal[(c)]	8	121	178	307	8	121	178	307

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

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

	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
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

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**
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 $(27) million and $(5) million at March 31, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(c) Excludes net assets of $1 million and $3 million at March 31, 2015 and December 31, 2014, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.
(d) Excludes $36 million and $35 million of cash surrender value of life insurance investment at March 31, 2015 and December 31, 2014, respectively, at Exelon Consolidated. Excludes $12 million and $11 million and of cash surrender value of life insurance investment at March 31, 2015 and December 31, 2014, respectively, at Generation.
(e) The mutual funds held by the Rabbi trusts at Exelon include $47 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at March 31, 2015, and $45 million related to deferred compensation and $1 million related to Supplemental Executive Retirement Plan at December 31, 2014.
(f) Includes collateral postings (received) to/from counterparties. Collateral posted (received) to/from counterparties, net of collateral paid to counterparties, totaled $425 million, $736 million and $185 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 2015. Collateral posted (received) from counterparties, net of collateral paid to counterparties, totaled $434 million, $800 million and $172 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2014.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

ComEd, PECO and BGE

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

	ComEd				PECO				BGE			
As of March 31, 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	$ 67	$	$	$ 67	$ 5	$	$	$ 5	$ 75	$	$	$ 75
Rabbi trust investments in mutual funds[(a)]					9			9	5			5
Total assets	67			67	14			14	80			80
Liabilities												
Deferred compensation obligation		(8)		(8)		(14)		(14)		(4)		(4)
Mark-to-market derivative liabilities[(b)]			(241)	(241)								
Total liabilities		(8)	(241)	(249)		(14)		(14)		(4)		(4)
Total net assets (liabilities)	$ 67	$ (8)	$ (241)	$ (182)	$ 14	$ (14)	$	$	$ 80	$ (4)	$	$ 76

	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)	$	