EXELON GENERATION CO LLC
Form 10-Q
May 10, 2013
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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, 2013

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 (312) 394-7398	23-2990190
333-85496	EXELON GENERATION COMPANY, LLC (a Pennsylvania limited liability company) 300 Exelon Way Kennett Square, Pennsylvania 19348-2473 (610) 765-5959	23-3064219

1-1839	COMMONWEALTH EDISON COMPANY (an Illinois corporation) 440 South LaSalle Street Chicago, Illinois 60605-1028 (312) 394-4321	36-0938600
000-16844	PECO ENERGY COMPANY (a Pennsylvania corporation) P.O. Box 8699 2301 Market Street Philadelphia, Pennsylvania 19101-8699 (215) 841-4000	23-0970240
1-1910	BALTIMORE GAS AND ELECTRIC COMPANY (a Maryland corporation) 2 Center Plaza 110 West Fayette Street Baltimore, Maryland 21201-3708 (410) 234-5000	52-0280210

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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, 2013 was:

Exelon Corporation Common Stock, without par value	855,849,302
Exelon Generation Company, LLC	not applicable
Commonwealth Edison Company Common Stock, $12.50 par value	127,016,781
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 in its corporate capacity as a holding company
CENG	Constellation Energy Nuclear Group, LLC
Constellation	Constellation Energy Group, Inc.
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
PEC L.P.	PECO Energy Capital, L.P.
PECO Trust III	PECO Capital Trust III
PECO Trust IV	PECO Energy Capital Trust IV
PETT	PECO Energy Transition Trust
Registrants	Exelon, Generation, ComEd, PECO and BGE, collectively
Other Terms and Abbreviations	
Note __ of the Exelon 2012 Form 10-K	Reference to specific Combined Note to Consolidated Financial Statements within Exelon s 2012 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
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
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

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GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
EGS	Electric Generation Supplier
EIMA	Energy Infrastructure Modernization Act (Illinois Senate Bill 1652 and Illinois House Bill 3036)
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
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
IPA	Illinois Power Agency
IRC	Internal Revenue Code
IRS	Internal Revenue Service
ISO	Independent System Operator
ISO-NE	ISO New England Inc.
ISO-NY	ISO New York
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 Rule
MBR	Market Based Rates Incentive
MDE	Maryland Department of the Environment
MDPSC	Maryland Public Service Commission
MGP	Manufactured Gas Plant
MISO	Midwest Independent Transmission System Operator, Inc.
mmcf	Million Cubic Feet
Moody s	Moody s Investor Service
MRV	Market-Related Value

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
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
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
PJM	PJM Interconnection, LLC
POLR	Provider of Last Resort
POR	Purchase of Receivables
PPA	Power Purchase Agreement
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
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

GLOSSARY OF TERMS AND ABBREVIATIONS

Other Terms and Abbreviations	
SFC	Supplier Forward Contract
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
SOS	Standard Offer Service
SPP	Southwest Power Pool
Tax Relief Act of 2010	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
TEG	Termoelectrica del Golfo
TEP	Termoelectrica Penoles
Upstream	Natural gas 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 the 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

Certain of the matters discussed in this Report are 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 a Registrant include (a) those factors discussed in the following sections of Exelon s 2012 Annual Report on Form 10-K: ITEM 1A. Risk Factors, as updated by Part II, ITEM 1A of this Report; ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations, as updated by Part I, ITEM 2. of this Report; and ITEM 8. Financial Statements and Supplementary Data: Note 19, as updated by Part I, Item 1. Financial Statements, Note 17 of this Report; and (b) other factors discussed herein and in other filings with the SEC by the Registrants. Readers are cautioned not to place undue reliance on these forward-looking statements, which apply only as of the date of this Report. None of the Registrants undertakes any obligation to publicly release any revision to its forward-looking statements to reflect events or circumstances after the date of this Report.

WHERE TO FIND MORE INFORMATION

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

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

(Unaudited)

(In millions, except per share data)	**Three Months Ended March 31, 2013**	**2012**
Operating revenues	$ 6,082	$ 4,690
Operating expenses		
Purchased power and fuel	2,981	1,765
Operating and maintenance	1,764	1,968
Depreciation and amortization	543	382
Taxes other than income	277	194
Total operating expenses	5,565	4,309
Equity in loss of unconsolidated affiliates	(9)	(22)
Operating income	508	359
Other income and (deductions)		
Interest expense, net	(617)	(189)
Interest expense to affiliates, net	(6)	(6)
Other, net	172	194
Total other income and (deductions)	(451)	(1)
Income before income taxes	57	358
Income taxes	56	158
Net income	1	200
Net income attributable to noncontrolling interests, preferred security dividends and preference stock dividends	5	
Net income (loss) on common stock	(4)	200
Other comprehensive income (loss), net of income taxes		
Pension and non-pension postretirement benefit plans:		
Prior service cost (benefit) reclassified to periodic benefit cost		1
Actuarial loss reclassified to periodic cost	51	41
Transition obligation reclassified to periodic cost		1
Pension and non-pension postretirement benefit plans valuation adjustment	75	(8)
Change in unrealized (loss) gain on cash flow hedges	(58)	215
Change in unrealized (loss) gain on marketable securities	(1)	1
Change in unrealized gain on equity investments	28	
Change in unrealized (loss) on foreign currency translation	(1)	
Other comprehensive income	94	251
Comprehensive income	$ 95	$ 451

Weighted average shares of common stock outstanding:

Basic	855	705
Diluted	855	707
Earnings per average common share basic:	$ (0.01)	$ 0.28
Earnings per average common share diluted:	$ (0.01)	$ 0.28
Dividends per common share	$ 0.53	$ 0.53

See the 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, 2013	2012
Cash flows from operating activities		
Net income	$ 1	$ 200
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	1,017	776
Deferred income taxes and amortization of investment tax credits	(610)	101
Net fair value changes related to derivatives	388	(73)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(66)	(103)
Other non-cash operating activities	231	530
Changes in assets and liabilities:		
Accounts receivable	(70)	394
Inventories	101	104
Accounts payable, accrued expenses and other current liabilities	(542)	(1,176)
Option premiums paid, net	(3)	(100)
Counterparty collateral received (posted), net	(186)	340
Income taxes	632	178
Pension and non-pension postretirement benefit contributions	(267)	(55)
Other assets and liabilities	233	(122)
Net cash flows provided by operating activities	859	994
Cash flows from investing activities		
Capital expenditures	(1,447)	(1,496)
Proceeds from nuclear decommissioning trust fund sales	677	3,680
Investment in nuclear decommissioning trust funds	(729)	(3,726)
Cash and restricted cash acquired from Constellation		964
Change in restricted cash	(12)	(8)
Other investing activities	40	(54)
Net cash flows used in investing activities	(1,471)	(640)
Cash flows from financing activities		
Changes in short-term debt	233	141
Issuance of long-term debt	149	
Retirement of long-term debt	(1)	(451)
Dividends paid on common stock	(450)	(350)
Proceeds from employee stock plans	12	12
Other financing activities	(45)	(1)
Net cash flows used in financing activities	(102)	(649)
Decrease in cash and cash equivalents	(714)	(295)
Cash and cash equivalents at beginning of period	1,486	1,016
Cash and cash equivalents at end of period	$ 772	$ 721

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 679	$ 1,411
Cash and cash equivalents of variable interest entities	93	75
Restricted cash and investments	83	86
Restricted cash and investments of variable interest entities	65	47
Accounts receivable, net		
Customer ($322 and $289 gross accounts receivable pledged as collateral as of March 31, 2013 and December 31, 2012, respectively)	2,835	2,789
Other	1,110	1,147
Accounts receivable, net, variable interest entities	285	292
Mark-to-market derivative assets	666	938
Unamortized energy contract assets	727	886
Inventories, net		
Fossil fuel	122	246
Materials and supplies	791	768
Deferred income taxes	331	131
Regulatory assets	765	764
Other	722	560
Total current assets	9,274	10,140
Property, plant and equipment, net	45,784	45,186
Deferred debits and other assets		
Regulatory assets	6,521	6,497
Nuclear decommissioning trust funds	7,559	7,248
Investments	1,181	1,184
Investments in affiliates	22	22
Investment in CENG	1,883	1,849
Goodwill	2,625	2,625
Mark-to-market derivative assets	706	937
Unamortized energy contracts assets	968	1,073
Pledged assets for Zion Station decommissioning	580	614
Other	1,140	1,186
Total deferred debits and other assets	23,185	23,235
Total assets	$ 78,243	$ 78,561

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EXELON CORPORATION AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 233	$
Short-term notes payable accounts receivable agreement	210	210
Long-term debt due within one year	2,085	975
Long-term debt due within one year of variable interest entities	79	72
Accounts payable	2,198	2,446
Accounts payable of variable interest entities	188	202
Accrued expenses	1,430	1,800
Deferred income taxes	29	58
Regulatory liabilities	418	368
Dividends payable	1	4
Mark-to-market derivative liabilities	181	352
Unamortized energy contract liabilities	410	455
Other	859	849
Total current liabilities	8,321	7,791
Long-term debt	16,210	17,190
Long-term debt to financing trusts	648	648
Long-term debt of variable interest entities	497	508
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	11,315	11,551
Asset retirement obligations	5,149	5,074
Pension obligations	3,161	3,428
Non-pension postretirement benefit obligations	2,672	2,662
Spent nuclear fuel obligation	1,020	1,020
Regulatory liabilities	4,115	3,981
Mark-to-market derivative liabilities	259	281
Unamortized energy contract liabilities	466	528
Payable for Zion Station decommissioning	372	432
Other	2,625	1,650
Total deferred credits and other liabilities	31,154	30,607
Total liabilities	56,830	56,744
Commitments and contingencies		
Preferred securities of subsidiary	87	87
Shareholders equity		
Common stock (No par value, 2,000 shares authorized, 856 shares and 855 shares outstanding at March 31, 2013 and December 31, 2012, respectively)	16,652	16,632
Treasury stock, at cost (35 shares at March 31, 2013 and December 31, 2012, respectively)	(2,327)	(2,327)
Retained earnings	9,437	9,893
Accumulated other comprehensive loss, net	(2,673)	(2,767)
Total shareholders equity	21,089	21,431

BGE preference stock not subject to mandatory redemption	193	193
Noncontrolling interest	44	106
Total equity	21,326	21,730
Total liabilities and shareholders equity	$ 78,243	$ 78,561

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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	Non-controlling Interest	Preferred and Preference Stock	Total Equity
Balance, December 31, 2012	889,525	$ 16,632	$ (2,327)	$ 9,893	$ (2,767)	$ 106	$ 193	$ 21,730
Net income (loss)				(4)		1	4	1
Long-term incentive plan activity	1,067	20						20
Common stock dividends				(452)				(452)
Consolidated VIE dividend to non-controlling interest						(63)		(63)
Preferred and preference stock dividends							(4)	(4)
Other comprehensive income net of income taxes of $(66)					94			94
Balance, March 31, 2013	890,592	$ 16,652	$ (2,327)	$ 9,437	$ (2,673)	$ 44	$ 193	$ 21,326

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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, 2013	2012
Operating revenues		
Operating revenues	$ 3,141	$ 2,373
Operating revenues from affiliates	392	370
Total operating revenues	3,533	2,743
Operating expenses		
Purchased power and fuel	2,169	1,044
Operating and maintenance	965	1,039
Operating and maintenance from affiliates	147	140
Depreciation and amortization	214	153
Taxes other than income	93	73
Total operating expenses	3,588	2,449
Equity in loss of unconsolidated affiliates	(9)	(22)
Operating (loss) income	(64)	272
Other income and (deductions)		
Interest expense	(82)	(54)
Other, net	128	178
Total other income and (deductions)	46	124
(Loss) income before income taxes	(18)	396
Income (benefit) taxes	(1)	230
Net (loss) income	(17)	166
Net income (loss) attributable to noncontrolling interests	1	(2)
Net (loss) income on membership interest	(18)	168
Other comprehensive (loss) income, net of income taxes		
Change in unrealized (loss) gain on cash flow hedges	(130)	252
Change in unrealized loss on foreign currency translation	(1)	
Change in unrealized loss on marketable securities	(1)	
Change in unrealized gain on equity investments	28	
Other comprehensive (loss) income	(104)	252
Comprehensive (loss) income	$ (121)	$ 418

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	Three Months Ended March 31, 2013	2012
Cash flows from operating activities		
Net (loss) income	$ (17)	$ 166
Adjustments to reconcile net (loss) income to net cash flows provided by operating activities:		
Depreciation, amortization, depletion and accretion, including nuclear fuel and energy contract amortization	688	547
Deferred income taxes and amortization of investment tax credits	(81)	165
Net fair value changes related to derivatives	406	(63)
Net realized and unrealized gains on nuclear decommissioning trust fund investments	(66)	(103)
Other non-cash operating activities	66	90
Changes in assets and liabilities:		
Accounts receivable	65	321
Receivables from and payables to affiliates, net	(23)	85
Inventories	29	59
Accounts payable, accrued expenses and other current liabilities	(261)	(782)
Option premiums paid, net	(3)	(100)
Counterparty collateral (paid) received, net	(203)	348
Income taxes	180	162
Pension and non-pension postretirement benefit contributions	(115)	(20)
Other assets and liabilities	(159)	(80)
Net cash flows provided by operating activities	506	795
Cash flows from investing activities		
Capital expenditures	(841)	(1,055)
Proceeds from nuclear decommissioning trust fund sales	677	3,680
Investment in nuclear decommissioning trust funds	(729)	(3,726)
Change in restricted cash	3	(1)
Cash acquired from Constellation		708
Other investing activities	25	(77)
Net cash flows used in investing activities	(865)	(471)
Cash flows from financing activities		
Issuance of long-term debt	149	
Retirement of long-term debt	(1)	(1)
Change in short-term debt	13	
Distribution to member	(211)	(600)
Other financing activities	(37)	
Net cash flows used in financing activities	(87)	(601)
Decrease in cash and cash equivalents	(446)	(277)
Cash and cash equivalents at beginning of period	671	496
Cash and cash equivalents at end of period	$ 225	$ 219

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
Assets		
Current assets		
Cash and cash equivalents	$ 132	$ 596
Cash and cash equivalents of variable interest entities	93	75
Restricted cash and cash equivalents of variable interest entities	13	16
Accounts receivable, net		
Customer	1,470	1,482
Other	286	472
Accounts receivable, net, variable interest entities	285	292
Mark-to-market derivative assets	666	938
Mark-to-market derivative assets with affiliates	85	226
Receivables from affiliates	132	141
Unamortized energy contract assets	727	886
Inventories, net		
Fossil fuel	92	130
Materials and supplies	635	626
Deferred income taxes	187	
Other	459	331
Total current assets	5,262	6,211
Property, plant and equipment, net	19,813	19,531
Deferred debits and other assets		
Nuclear decommissioning trust funds	7,559	7,248
Investments	411	420
Investment in CENG	1,883	1,849
Mark-to-market derivative assets	694	924
Prepaid pension asset	2,032	1,975
Pledged assets for Zion Station decommissioning	580	614
Unamortized energy contract assets	968	1,073
Other	789	836
Total deferred debits and other assets	14,916	14,939
Total assets	$ 39,991	$ 40,681

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EXELON GENERATION COMPANY, LLC AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND EQUITY		
Current liabilities		
Short-term borrowings	$ 13	$
Long-term debt due within one year	523	24
Long-term debt due within one year of variable interest entities	5	4
Accounts payable	1,162	1,346
Accounts payable of variable interest entities	188	202
Accrued expenses	904	1,116
Payables to affiliates	165	193
Deferred income taxes	18	128
Mark-to-market derivative liabilities	166	334
Unamortized energy contract liabilities	349	378
Other	371	372
Total current liabilities	3,864	4,097
Long-term debt	4,893	5,245
Long-term debt to affiliate	1,997	2,007
Long-term debt of variable interest entities	203	203
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	5,598	5,398
Asset retirement obligations	5,013	4,938
Non-pension postretirement benefit obligations	785	755
Spent nuclear fuel obligation	1,020	1,020
Payables to affiliates	2,531	2,397
Mark-to-market derivative liabilities	199	232
Unamortized energy contract liabilities	457	516
Payable for Zion Station decommissioning	372	432
Other	789	776
Total deferred credits and other liabilities	16,764	16,464
Total liabilities	27,721	28,016
Commitments and contingencies		
Equity		
Member s equity		
Membership interest	8,876	8,876
Undistributed earnings	2,939	3,168
Accumulated other comprehensive income, net	409	513
Total member s equity	12,224	12,557
Noncontrolling interest	46	108
Total equity	12,270	12,665
Total liabilities and equity	$ 39,991	$ 40,681

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)

	Member s Equity				
(In millions)	**Membership Interest**	**Undistributed Earnings**	**Accumulated Other Comprehensive Income, net**	**Noncontrolling Interest**	**Total Equity**
Balance, December 31, 2012	$ 8,876	$ 3,168	$ 513	$ 108	$ 12,665
Net income (loss)		(18)		1	(17)
Distribution to member		(211)			(211)
Consolidated VIE dividend to non-controlling interest				(63)	(63)
Other comprehensive loss, net of income taxes of $68			(104)		(104)
Balance, March 31, 2013	$ 8,876	$ 2,939	$ 409	$ 46	$ 12,270

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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, 2013	2012
Operating revenues		
Operating revenues	$ 1,159	$ 1,387
Operating revenues from affiliates	1	1
Total operating revenues	1,160	1,388
Operating expenses		
Purchased power	237	373
Purchased power from affiliate	145	247
Operating and maintenance	292	276
Operating and maintenance from affiliate	36	42
Depreciation and amortization	167	149
Taxes other than income	74	75
Total operating expenses	951	1,162
Operating income	209	226
Other income and (deductions)		
Interest expense	(350)	(79)
Interest expense to affiliates, net	(3)	(3)
Other, net	5	4
Total other income and (deductions)	(348)	(78)
(Loss) income before income taxes	(139)	148
Income (benefit) taxes	(58)	61
Net (loss) income	(81)	87
Other comprehensive income, net of income taxes		
Change in unrealized gain on marketable securities		1
Other comprehensive income		1
Comprehensive (loss) income	$ (81)	$ 88

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Three Months Ended March 31, 2013**	**2012**
Cash flows from operating activities		
Net (loss) income	$ (81)	$ 87
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	167	149
Deferred income taxes and amortization of investment tax credits	(295)	57
Other non-cash operating activities	42	60
Changes in assets and liabilities:		
Accounts receivable	1	58
Receivables from and payables to affiliates, net	(32)	15
Inventories	(9)	(3)
Accounts payable, accrued expenses and other current liabilities	(73)	(159)
Counterparty collateral received (paid), net	17	(8)
Income taxes	208	116
Pension and non-pension postretirement benefit contributions	(118)	(9)
Other assets and liabilities	231	(72)
Net cash flows provided by operating activities	58	291
Cash flows from investing activities		
Capital expenditures	(346)	(291)
Proceeds from sales of investments	2	10
Purchases of investments	(1)	(5)
Other investing activities	9	6
Net cash flows used in investing activities	(336)	(280)
Cash flows from financing activities		
Changes in short-term debt	220	302
Retirement of long-term debt		(450)
Dividends paid on common stock	(55)	(75)
Other financing activities	(1)	(3)
Net cash flows provided by (used in) financing activities	164	(226)
Decrease in cash and cash equivalents	(114)	(215)
Cash and cash equivalents at beginning of period	144	234
Cash and cash equivalents at end of period	$ 30	$ 19

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 30	$ 144
Accounts receivable, net		
Customer	495	539
Other	513	452
Inventories, net	100	91
Deferred income taxes	37	83
Counterparty collateral deposited	36	53
Regulatory assets	301	388
Other	26	25
Total current assets	1,538	1,775
Property, plant and equipment, net	14,020	13,826
Deferred debits and other assets		
Regulatory assets	681	666
Investments	7	8
Investments in affiliates	6	6
Goodwill	2,625	2,625
Receivables from affiliates	2,314	2,039
Prepaid pension asset	1,729	1,661
Other	336	299
Total deferred debits and other assets	7,698	7,304
Total assets	$ 23,256	$ 22,905

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COMMONWEALTH EDISON COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term borrowings	$ 220	$
Long-term debt due within one year	869	252
Accounts payable	384	379
Accrued expenses	199	295
Payables to affiliates	68	97
Customer deposits	136	136
Regulatory liabilities	166	170
Mark-to-market derivative liability	15	18
Mark-to-market derivative liability with affiliate	85	226
Other	94	82
Total current liabilities	2,236	1,655
Long-term debt	4,699	5,315
Long-term debt to financing trust	206	206
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	3,933	4,272
Asset retirement obligations	100	99
Non-pension postretirement benefits obligations	300	273
Regulatory liabilities	3,337	3,229
Mark-to-market derivative liability	60	49
Other	1,026	484
Total deferred credits and other liabilities	8,756	8,406
Total liabilities	15,897	15,582
Commitments and contingencies		
Shareholders equity		
Common stock	1,588	1,588
Other paid-in capital	5,186	5,014
Retained earnings	585	721
Total shareholders equity	7,359	7,323
Total liabilities and shareholders equity	$ 23,256	$ 22,905

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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	Accumulated Other Comprehensive Income, net	Total Shareholders Equity
Balance, December 31, 2012	$ 1,588	$ 5,014	$ (1,639)	$ 2,360	$	$ 7,323
Net income (loss)			(81)			(81)
Common stock dividends				(55)		(55)
Parent tax matter indemnification		172				172
Balance, March 31, 2013	$ 1,588	$ 5,186	$ (1,720)	$ 2,305	$	$ 7,359

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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, 2013	2012
Operating revenues		
Operating revenues	$ 895	$ 874
Operating revenues from affiliates		1
Total operating revenues	895	875
Operating expenses		
Purchased power and fuel	265	300
Purchased power from affiliate	141	111
Operating and maintenance	164	173
Operating and maintenance from affiliates	24	30
Depreciation and amortization	57	53
Taxes other than income	41	31
Total operating expenses	692	698
Operating income	203	177
Other income and (deductions)		
Interest expense	(26)	(28)
Interest expense to affiliates, net	(3)	(3)
Other, net	3	2
Total other income and (deductions)	(26)	(29)
Income before income taxes	177	148
Income taxes	55	51
Net income	122	97
Preferred security dividends	1	1
Net income on common stock	$ 121	$ 96
Comprehensive income, net of income taxes		
Net income	$ 122	$ 97
Other comprehensive income, net of income taxes		
Change in unrealized gain on marketable securities		1
Other comprehensive income		1
Comprehensive income	$ 122	$ 98

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In millions)	**Three Months Ended March 31, 2013**	**2012**
Cash flows from operating activities		
Net income	$ 122	$ 97
Adjustments to reconcile net income to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	57	53
Deferred income taxes and amortization of investment tax credits	19	10
Other non-cash operating activities	39	40
Changes in assets and liabilities:		
Accounts receivable	(50)	31
Receivables from and payables to affiliates, net	1	12
Inventories	44	39
Accounts payable, accrued expenses and other current liabilities	(17)	(71)
Income taxes	29	76
Pension and non-pension postretirement benefit contributions	(11)	(5)
Other assets and liabilities	(38)	(110)
Net cash flows provided by operating activities	195	172
Cash flows from investing activities		
Capital expenditures	(122)	(96)
Changes in intercompany money pool	(50)	(35)
Change in restricted cash		(3)
Other investing activities	1	4
Net cash flows used in investing activities	(171)	(130)
Cash flows from financing activities		
Dividends paid on common stock	(83)	(87)
Dividends paid on preferred securities	(1)	(1)
Net cash flows used in financing activities	(84)	(88)
Decrease in cash and cash equivalents	(60)	(46)
Cash and cash equivalents at beginning of period	362	194
Cash and cash equivalents at end of period	$ 302	$ 148

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 302	$ 362
Accounts receivable, net ($322 and $289 gross accounts receivable pledged as collateral as of March 31, 2013 and December 31, 2012, respectively)		
Customer	395	364
Other	138	161
Inventories, net		
Fossil fuel	18	65
Materials and supplies	20	19
Deferred income taxes	40	40
Receivable from Exelon intercompany money pool	50	
Prepaid utility taxes	96	21
Regulatory assets	33	32
Other	32	30
Total current assets	1,124	1,094
Property, plant and equipment, net	6,141	6,078
Deferred debits and other assets		
Regulatory assets	1,389	1,378
Investments	23	22
Investments in affiliates	8	8
Receivable from affiliates	392	360
Prepaid pension asset	378	373
Other	36	40
Total deferred debits and other assets	2,226	2,181
Total assets	$ 9,491	$ 9,353

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Short-term notes payable accounts receivable agreement	$ 210	$ 210
Long-term debt due within one year	300	300
Accounts payable	224	244
Accrued expenses	97	82
Payables to affiliates	76	76
Customer deposits	49	51
Regulatory liabilities	205	169
Other	28	26
Total current liabilities	1,189	1,158
Long-term debt	1,648	1,647
Long-term debt to financing trusts	184	184
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	2,374	2,331
Asset retirement obligations	29	29
Non-pension postretirement benefits obligations	289	284
Regulatory liabilities	560	538
Other	111	113
Total deferred credits and other liabilities	3,363	3,295
Total liabilities	6,384	6,284
Commitments and contingencies		
Preferred securities	87	87
Shareholder s equity		
Common stock	2,388	2,388
Retained earnings	631	593
Accumulated other comprehensive income, net	1	1
Total shareholder s equity	3,020	2,982
Total liabilities and shareholders equity	$ 9,491	$ 9,353

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PECO ENERGY COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS EQUITY

(Unaudited)

(In millions)	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income, net	Total Shareholders Equity
Balance, December 31, 2012	$ 2,388	$ 593	$ 1	$ 2,982
Net income		122		122
Common stock dividends		(83)		(83)
Preferred security dividends		(1)		(1)
Balance, March 31, 2013	$ 2,388	$ 631	$ 1	$ 3,020

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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, 2013	2012
Operating revenues		
Operating revenues	$ 876	$ 694
Operating revenues from affiliates	4	3
Total operating revenues	880	697
Operating expenses		
Purchased power and fuel	313	293
Purchased power from affiliate	113	92
Operating and maintenance	124	154
Operating and maintenance from affiliates	19	42
Depreciation and amortization	93	79
Taxes other than income	55	48
Total operating expenses	717	708
Operating income (loss)	163	(11)
Other income and (deductions)		
Interest expense	(33)	(41)
Other, net	5	6
Total other income and (deductions)	(28)	(35)
Income (loss) before income taxes	135	(46)
Income taxes	55	(16)
Net income (loss)	80	(30)
Preference stock dividends	3	3
Net income (loss) on common stock	$ 77	$ (33)
Comprehensive income (loss)	$ 80	$ (30)

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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)	**2013**	**2012**
Cash flows from operating activities		
Net (loss) income	$ 80	$ (30)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:		
Depreciation, amortization and accretion	93	79
Deferred income taxes and amortization of investment tax credits	73	40
Other non-cash operating activities	42	179
Changes in assets and liabilities:		
Accounts receivable	(98)	6
Receivables from and payables to affiliates, net	(22)	31
Inventories	35	50
Accounts payable, accrued expenses and other current liabilities	(11)	(22)
Income taxes	(36)	(57)
Pension and non-pension postretirement benefit contributions	(5)	(7)
Other assets and liabilities	34	(11)
Net cash flows provided by operating activities	185	258
Cash flows from investing activities		
Capital expenditures	(134)	(130)
Change in restricted cash	(22)	(19)
Other investing activities	2	3
Net cash flows used in investing activities	(154)	(146)
Cash flows from financing activities		
Dividends paid on preference stock	(3)	(3)
Change in restricted cash for dividends	(3)	
Other financing activities	1	(1)
Net cash flows used in financing activities	(5)	(4)
Increase in cash and cash equivalents	26	108
Cash and cash equivalents at beginning of period	89	49
Cash and cash equivalents at end of period	$ 115	$ 157

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
ASSETS		
Current assets		
Cash and cash equivalents	$ 115	$ 89
Restricted cash and cash equivalents	3	
Restricted cash and cash equivalents of variable interest entity	52	30
Accounts receivable, net		
Customer	476	403
Other	135	117
Income taxes receivable	39	3
Inventories, net		
Gas held in storage	12	51
Materials and supplies	35	31
Deferred income taxes	7	1
Prepaid utility taxes	28	57
Regulatory assets	148	190
Other	8	8
Total current assets	1,058	980
Property, plant and equipment, net	5,568	5,498
Deferred debits and other assets		
Regulatory assets	522	522
Investments	5	5
Investments in affiliates	8	8
Prepaid pension asset	456	467
Other	22	26
Total deferred debits and other assets	1,013	1,028
Total assets	$ 7,639	$ 7,506

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BALTIMORE GAS AND ELECTRIC COMPANY AND SUBSIDIARY COMPANIES

CONSOLIDATED BALANCE SHEETS

(In millions)	March 31, 2013 (Unaudited)	December 31, 2012
LIABILITIES AND SHAREHOLDERS EQUITY		
Current liabilities		
Long-term debt due within one year	$ 400	$ 400
Long-term debt of variable interest entity due within one year	67	67
Accounts payable	186	195
Accrued expenses	100	106
Payables to affiliates	45	65
Customer deposits	69	71
Regulatory liabilities	47	29
Other	45	47
Total current liabilities	959	980
Long-term debt	1,446	1,446
Long-term debt to financing trust	258	258
Long-term debt of variable interest entity	265	265
Deferred credits and other liabilities		
Deferred income taxes and unamortized investment tax credits	1,738	1,658
Asset retirement obligations	7	8
Non-pension postretirement benefits obligations	227	229
Regulatory liabilities	218	214
Other	86	90
Total deferred credits and other liabilities	2,276	2,199
Total liabilities	5,204	5,148
Commitments and contingencies		
Shareholder s equity		
Common stock	1,360	1,360
Retained earnings	885	808
Total shareholder s equity	2,245	2,168
Preference stock not subject to mandatory redemption	190	190
Total equity	2,435	2,358
Total liabilities and shareholders equity	$ 7,639	$ 7,506

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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, 2012	$ 1,360	$ 808	$ 2,168	$ 190	$ 2,358
Net income		80	80		80
Preference stock dividends		(3)	(3)		(3)
Balance, March 31, 2013	$ 1,360	$ 885	$ 2,245	$ 190	$ 2,435

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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. Prior to March 12, 2012, Exelon s principal, wholly owned subsidiaries included ComEd, PECO and Generation. On March 12, 2012, Constellation merged into Exelon with Exelon continuing as the surviving corporation pursuant to the transactions contemplated by the Agreement and Plan of Merger (the Merger Agreement). As a result of the merger transaction, Generation now includes the former Constellation generation and customer supply operations. BGE, formerly Constellation s regulated utility subsidiary, is now a subsidiary of Exelon. Refer to Note 4 Merger and Acquisitions for further information regarding the merger transaction.

The energy generation business includes:

Generation: The integrated business consists of owned and contracted generation and investments in electric generating facilities that are marketed through its leading customer facing activities. The customer facing activities include wholesale and retail customer supply of electric and natural gas products and services, including renewable energy products, risk management services and investments in natural gas exploration and production activities.

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.

For financial statement purposes, beginning on March 12, 2012, disclosures that solely relate to Constellation or BGE activities now also apply to Exelon, unless otherwise noted. When appropriate, Exelon, Generation, ComEd, PECO and BGE are named specifically for their related activities and disclosures.

Exelon did not apply push-down accounting to BGE. As a result, BGE continues to maintain its reporting requirements as an SEC registrant. The information disclosed for BGE represents the activity of the standalone entity for the three months ended March 31, 2013 and 2012 and the financial position as of March 31, 2013 and December 31, 2012. However, for Exelon s financial reporting, Exelon is reporting BGE activity for the three months ended March 31, 2013 and from March 12, 2012 through March 31, 2012 and the financial position as of March 31, 2013 and December 31, 2012.

Each of the Registrant s Consolidated Financial Statements includes the accounts of its subsidiaries. All intercompany transactions have been eliminated.

For the three months ended March 31, 2013, BGE recorded a $2 million correcting adjustment to decrease amortization expense related to regulatory assets that was originally recorded during 2012. Exelon and BGE have concluded that this correcting adjustment is not material to their results of operations or cash flows for the three months ended March 31, 2013 or any prior period. Exelon and BGE do not expect this correcting adjustment to have a material impact on their results of operations or cash flows for the year ended December 31, 2013.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The accompanying consolidated financial statements as of March 31, 2013 and 2012 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, 2012 Consolidated Balance Sheets were obtained from audited financial statements. Certain prior year amounts in BGE s Consolidated Statements of Cash Flows, Exelon s, Generation s and BGE s Consolidated Statements of Operations and Comprehensive Income and in Exelon s, Generation s, ComEd s, and BGE s Consolidated Balance Sheets have been reclassified between line items for comparative purposes. The reclassifications did not materially affect any of the Registrants net income or cash flows from operating activities. Financial results for this interim period are not necessarily indicative of results that may be expected for any other interim period or for fiscal year ended December 31, 2013. 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 Notes to Combined Consolidated Financial Statements of all Registrants included in ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA of their respective 2012 Form 10-K Reports.

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

The following recently issued accounting standards were adopted by the Registrants during the period.

Presentation of Items Reclassified out of Accumulated Other Comprehensive Income

In February 2013, the FASB issued authoritative guidance requiring entities to present either in the notes or parenthetically on the face of the financial statements, reclassifications from each component of accumulated other comprehensive income and the affected income statement line items. Entities only need to disclose the affected income statement line item for components reclassified to net income in their entirety; otherwise, a cross-reference to the related note should be provided. This guidance is effective for the Registrants for periods beginning after December 15, 2012 and is required to be applied prospectively. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 15 Changes in Accumulated Other Comprehensive Income for the new disclosures.

Disclosures About Offsetting Assets and Liabilities

In December 2011 (and amended in January 2013), the FASB issued authoritative guidance requiring entities to disclose both gross and net information about recognized derivative instruments, including bifurcated embedded derivatives, repurchase and reverse repurchase agreements, and securities borrowing or lending transactions that are offset on the balance sheet or subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the balance sheet. This guidance is effective for the Registrants for periods beginning on or after January 1, 2013 and is required to be applied retrospectively. This guidance is primarily applicable to certain derivative transactions for Exelon and Generation. As this guidance provides only disclosure requirements, the adoption of this standard did not impact the Registrants results of operations, cash flows or financial positions. See Note 9 Derivative Financial Instruments for the new disclosures.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 impact the entity s economic performance.

As of March 31, 2013 and December 31, 2012, the Registrant s consolidated five VIEs or VIE groups for which the Registrants were the primary beneficiary, and the Registrants had significant interests in nine other VIEs 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

The Registrants consolidated VIEs consist of:

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

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. In the case of BondCo, BGE is required to remit all payments it receives from all residential customers for non-bypassable, rate stabilization charges to BondCo. During the three months ended March 31, 2013 and 2012, BGE remitted $22 million and $20 million, respectively, to BondCo.
- Except for providing capital funding to the solar entities for ongoing construction of the solar power facilities and a $75 million parental guarantee to the third-party gas supplier in support of the retail gas group, during the three months ended March 31, 2013 and year ended December 31, 2012:
  - Exelon, Generation and BGE did not provide any additional financial support to the VIEs;

Exelon, Generation and BGE did not have any 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.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The carrying amounts and classification of the consolidated VIEs assets and liabilities included in the Registrants consolidated financial statements at March 31, 2013 and December 31, 2012 are as follows:

	March 31, 2013			December 31, 2012		
	Exelon(a)(b)	Generation(b)	BGE	Exelon(a)(b)	Generation(b)	BGE
Current assets	$ 551	$ 491	$ 52	$ 550	$ 519	$ 30
Noncurrent assets	1,947	1,918		1,802	1,762	
Total assets	$ 2,498	$ 2,409	$ 52	$ 2,352	$ 2,281	$ 30
Current liabilities	$ 575	$ 492	$ 76	$ 685	$ 613	$ 71
Noncurrent liabilities	986	693	265	837	532	265
Total liabilities	$ 1,561	$ 1,185	$ 341	$ 1,522	$ 1,145	$ 336

(a) Includes certain purchase accounting adjustments not pushed down to the BGE standalone entity.
(b) Includes total assets of $116 million and total liabilities of $59 million as of March 31, 2013 and total asset of $116 million and total liabilities of $62 million as of December 31, 2012 related to deferred and accrued taxes that are not restricted for use by the consolidated VIEs that have recorded such assets and liabilities.

Unconsolidated Variable Interest Entities

Exelon s and Generation s variable interests in unconsolidated VIEs generally include three transaction types: (1) equity method investments, (2) energy purchase and sale contracts, and (3) fuel purchase commitments. For the equity method investments, the carrying amount of the investments is reflected on their Consolidated Balance Sheets in investments in affiliates. 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, except as noted in the table above, Exelon and Generation have not provided material debt or equity support, or provided liquidity arrangements, performance guarantees or other commitments 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.

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

- Fuel purchase commitments where Generation has a variable interest, but the variable interest is not significant and Generation is not the primary beneficiary, thus consolidation is not required.

ComEd s, PECO s and BGE s retail operations frequently include the purchase of electricity and RECs through procurement contracts of varying durations. None of ComEd, PECO or BGE considers itself the primary beneficiary of any VIEs as a result of these commercial arrangements.

Investment in energy development projects for which Generation has concluded that consolidation is not required.

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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, 2013 and December 31, 2012, Exelon and Generation did have significant variable interests in nine VIEs for which they were not the primary beneficiary; including certain equity method investments and certain commercial agreements. The following tables present summary information about the significant unconsolidated VIE entities:

March 31, 2013	**Commercial Agreement VIEs**	**Equity Method Investment VIEs**	**Total**
Total assets(a)	$ 360	$ 338	$ 698
Total liabilities(a)	186	95	281
Registrants ownership interest(a)		98	98
Other ownership interests(a)	174	145	319
Registrants maximum exposure to loss:			
Letters of credit	1		1
Carrying amount of equity method investments		78	78
Contract intangible asset	8		8
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning(b)	49		49

December 31, 2012	**Commercial Agreement VIEs**	**Equity Method Investment VIEs**	**Total**
Total assets(a)	$ 386	$ 354	$ 740
Total liabilities(a)	219	114	333
Registrants ownership interest(a)		97	97
Other ownership interests(a)	167	143	310
Registrants maximum exposure to loss:			
Letters of credit	5		5
Carrying amount of equity method investments		77	77
Contract intangible asset	8		8
Debt and payment guarantees		5	5
Net assets pledged for Zion Station decommissioning(b)	50		50

(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 Generation s and Exelon s Consolidated Balance Sheets related to the asset sale agreement with ZionSolutions, LLC. The net assets pledged for Zion Station decommissioning includes gross pledged assets of $580 million and $614 million as of March 31, 2013 and December 31, 2012, respectively; offset by payables to ZionSolutions LLC of $531 million and $564 million as of March 31, 2013 and December 31, 2012, respectively. These items are included to provide information regarding the relative size of the ZionSolutions LLC unconsolidated VIE.

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

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

4. Merger and Acquisitions

Merger with Constellation (Exelon, Generation, ComEd, PECO and BGE)

Description of Transaction

On March 12, 2012, Exelon completed the merger contemplated by the Merger Agreement, among Exelon, Bolt Acquisition Corporation, a wholly owned subsidiary of Exelon (Merger Sub), and Constellation. As a result of that merger, Merger Sub was merged into Constellation (the Initial Merger) and Constellation became a wholly owned subsidiary of Exelon. Following the completion of the Initial Merger, Exelon and Constellation completed a series of internal corporate organizational restructuring transactions. Constellation merged with and into Exelon, with Exelon continuing as the surviving corporation (the Upstream Merger). Simultaneously with the Upstream Merger, Constellation s interest in RF HoldCo LLC, which holds Constellation s interest in BGE, was transferred to Exelon Energy Delivery Company, LLC, a wholly owned subsidiary of Exelon that also owns Exelon s interests in ComEd and PECO. Following the Upstream Merger and the transfer of RF HoldCo LLC, Exelon contributed to Generation certain subsidiaries, including those with generation and customer supply operations that were acquired from Constellation as a result of the Initial Merger and the Upstream Merger.

Regulatory Matters

In December 2011, Exelon and Constellation reached a settlement with the State of Maryland and the City of Baltimore and other interested parties in connection with the regulatory proceedings related to the merger that were pending before the MDPSC. As part of this settlement and the application for approval of the merger by MDPSC, Exelon agreed to provide a package of benefits to BGE customers, the City of Baltimore and the State of Maryland, resulting in an estimated direct investment in the State of Maryland of more than $1 billion.

The direct investment estimate includes $95 million to $120 million for the requirement to cause construction of a headquarters building in Baltimore for Generation s competitive energy businesses. On March 20, 2013, Generation signed a 20 year lease agreement that is contingent upon the developer obtaining financing for the construction of the building. Once the financing conditions are met, construction will commence and the building is expected to be ready for occupancy within 2 years. The direct investment estimate also includes $625 million for Exelon s and Generation s commitment to develop or assist in development of 285 300 MWs of new generation in Maryland, expected to be completed over a period of 10 years. Such costs, which are expected to be primarily capital in nature, will be recognized as incurred. As of March 31, 2013, amounts reflected in the Exelon and Generation consolidated financial statements for these expenditure commitments were immaterial.

The settlement agreement contemplates various options for complying with the new generation development commitments, including building or acquiring generating assets, making subsidy or compliance payments, or in circumstances in which the generation build is delayed, making liquidated damages payments. Exelon and Generation expect that the majority of these commitments will be satisfied by building or acquiring generating assets, and therefore will be primarily capital in nature and recognized as incurred. If in the future Exelon determines that it is probable that it will make subsidy, compliance or liquidated damages payments related to the new generation development commitments, Exelon will record a liability at that time. As of March 31, 2013, it is reasonably possible that Exelon will be required to make subsidy or liquidated damages payments of approximately $40 million rather than build one of the generation projects contemplated by the commitments, given that the generation build is dependent upon the passage of legislation and other conditions that Exelon does not control.

Associated with certain of the regulatory approvals required for the merger, on November 30, 2012, a subsidiary of Generation sold three Maryland generating stations and associated assets, Brandon Shores and H.A. Wagner in Anne Arundel County, Maryland, and C.P. Crane in Baltimore County, Maryland, to Raven Power Holdings LLC (Raven Power), a subsidiary of Riverstone Holdings LLC. In 2012, Exelon and Generation

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

recorded a pre-tax loss of $272 million to reflect the difference between the sales price and the carrying value of the generating stations and associated assets. In the first quarter of 2013, Exelon and Generation recorded a pre-tax gain of $8 million to reflect the final settlement of the sales price with Raven Power.

Accounting for the Merger Transaction

The fair value of Constellation s non-regulated business assets acquired and liabilities assumed was determined based on significant estimates and assumptions that are judgmental in nature, including projected future cash flows (including timing); discount rates reflecting risk inherent in the future cash flows; and future market prices. There were also judgments made to determine the expected useful lives assigned to each class of assets acquired and duration of liabilities assumed.

The financial statements of BGE do not include fair value adjustments for assets or liabilities subject to rate-setting provisions for BGE. BGE is subject to the rate-setting authority of FERC and the MDPSC and is accounted for pursuant to the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for BGE provide revenue derived from costs including a return on investment of assets and liabilities included in rate base. Except for debt, fuel supply contracts and regulatory assets not earning a return, the fair values of BGE s tangible and intangible assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values and, therefore, do not reflect any net adjustments related to these amounts. For BGE s debt, fuel supply contracts and regulatory assets not earning a return, the difference between fair value and book value of BGE s assets acquired and liabilities assumed is recorded as a regulatory asset and liability at Exelon Corporate as Exelon did not apply push-down accounting to BGE. See Note 1 Basis of Presentation for additional information on BGE s push-down accounting treatment. Also see Note 5 Regulatory Matters for additional information on BGE s regulatory assets.

The preliminary valuations performed in the first quarter of 2012 were updated in the second, third and fourth quarters of 2012, with the most significant adjustments to the preliminary valuation amounts having been made to the fair values assigned to the acquired power supply and fuel contracts, unregulated property, plant and equipment and investments in affiliates. There were no significant adjustments to the purchase price allocation in the first quarter of 2013 and the purchase price allocation is now final.

The purchase price allocation of the Initial Merger of Exelon with Constellation and Exelon s contribution of certain subsidiaries of Constellation to Generation at March 31, 2013 was as follows:

Purchase Price Allocation, excluding amortization	**Exelon**	**Generation**
Current assets	$ 4,936	$ 3,638
Property, plant and equipment	9,342	4,054
Unamortized energy contracts	3,218	3,218
Other intangibles, trade name and retail relationships	457	457
Investment in affiliates	1,942	1,942
Pension and OPEB regulatory asset	740	
Other assets	2,265	1,266
Total assets	22,900	14,575
Current liabilities	3,408	2,804
Unamortized energy contracts	1,722	1,512
Long-term debt, including current maturities	5,632	2,972
Noncontrolling interest	90	90
Deferred credits and other liabilities and preferred securities	4,683	1,933

Total liabilities, preferred securities and noncontrolling interest	15,535	9,311
Total purchase price	$ 7,365	$ 5,264

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Intangible Assets Recorded

For the power supply and fuel contracts acquired from Constellation, the difference between the contract price and the market price at the date of the merger was recognized as either an intangible asset or liability based on whether the contracts were in or out-of-the-money. The fair value amounts are amortized over the life of the contract in relation to the present value of the underlying cash flows as of the merger date. Amortization expense and income are recorded through purchased power and fuel expense or operating revenues. Exelon and Generation present separately in their Consolidated Balance Sheets the unamortized energy contract assets and liabilities for these contracts. Exelon s and Generation s amortization expense for the three months ended March 31, 2013 and the period March 12, 2012 to March 31, 2012 amounted to \$170 million and \$131 million, respectively. This amortization expense excludes the \$19 million and \$9 million in amortization of the regulatory asset for the three months ended March 31, 2013 and the period March 12, 2012 to March 31, 2012 and equally offsetting amortization of the fuel supply contract liability recorded at Exelon Corporate in the Consolidated Statement of Operations. The weighted-average amortization period is approximately 1.5 years.

Exelon s and Generation s straight line amortization expense for the fair value of the Constellation trade name intangible asset for the three months ended March 31, 2013 and the period March 12, 2012 to March 31, 2012 amounted to \$6 million and \$2 million, respectively. The amortization period is approximately 10 years. The trade name intangible asset is included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

The intangible assets for the fair value of the retail relationships are amortized as amortization expense on a straight line basis over the useful life of the underlying assets averaging approximately 12.4 years. Exelon s and Generation s straight line amortization expense for the three months ended March 31, 2013 and the period March 12, 2012 to March 31, 2012 amounted to \$5 million and \$1 million, respectively. The retail relationships intangible assets are included in deferred debits and other assets within Exelon s and Generation s Consolidated Balance Sheets.

Exelon s intangible assets and liabilities acquired through the merger with Constellation included in its Consolidated Balance Sheets, along with the future estimated amortization, were as follows as of March 31, 2013:

					Estimated amortization expense					
Description	Weighted Average Amortization	Gross	Accumulated Amortization	Net	Remainder of 2013	2014	2015	2016	2017	2018 and Beyond
Unamortized energy contracts, net(a)	1.5	$ 1,496	$ (1,133)	$ 363	$ 243	$ 73	$ 19	$ (31)	$ (22)	$ 81
Trade name	10.0	243	(26)	217	18	24	24	24	24	103
Retail relationships	12.4	214	(20)	194	15	19	19	19	19	103
Total, net		$ 1,953	$ (1,179)	$ 774	$ 276	$ 116	$ 62	$ 12	$ 21	$ 287

(a) Includes the fair value of BGE s power and gas supply contracts of \$70 million for which an offsetting regulatory asset was also recorded.

Impact of Merger

It is impracticable to determine the overall financial statement impact for the Constellation subsidiaries contributed down to Generation following the Upstream Merger for the three months ended March 31, 2013 and 2012. Upon closing of the merger, the operations of these Constellation subsidiaries were integrated into Generation s operations and are therefore not fully distinguishable after the merger.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The impact of BGE on Exelon s Consolidated Statement of Operations and Comprehensive Income includes operating revenues of $880 million and net income of $80 million during the three months ended March 31, 2013, and operating revenues of $52 million and net loss of $65 million during the three months ended March 31, 2012.

During the three months ended March 31, 2013, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $33 million, $23 million, $4 million, $3 million and $2 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $6 million, $4 million and $2 million as a regulatory asset as of March 31, 2013. Additionally, Exelon and BGE established a regulatory asset of $6 million as of March 31, 2013 for previously incurred 2012 merger and integration-related costs.

During the three months ended March 31, 2012, Exelon, Generation, ComEd, PECO and BGE incurred merger and integration-related costs of $516 million, $110 million, $18 million, $7 million and $169 million, respectively. Of these amounts, Exelon, ComEd and BGE deferred $32 million, $16 million and $16 million as a regulatory asset as of March 31, 2012. The costs incurred are classified primarily within Operating and Maintenance Expense in the Registrants respective Consolidated Statements of Operations and Comprehensive Income, with the exception of the BGE customer rate credit and the credit facility fees, which are included as a reduction to operating revenues and other, net, respectively, for the three months ended March 31, 2012.

Severance Costs

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

Upon closing the merger with Constellation, Exelon recorded a severance accrual for the anticipated employee position reductions as a result of the post-merger integration. The majority of these positions are corporate and Generation support positions. Since then, Exelon has identified specific employees to be severed pursuant to the merger-related staffing and selection process; as well as employees that were previously identified for severance but have since accepted another position within Exelon and are no longer receiving a severance benefit. Exelon adjusts its accrual each quarter to reflect its best estimate of remaining severance costs. The amount of severance expense associated with the post-merger integration recognized for the three months ended March 31, 2013 and March 31, 2012, for Exelon is $3 million and $83 million, which includes $3 million and $45 million for Generation, $0 million and $11 million for ComEd, $0 million and $5 million for PECO and $0 million and $16 million for BGE, respectively. Estimated costs to be incurred after March 31, 2013 are not material. In addition, certain employees identified during the staffing and selection process also receive pension and other postretirement benefits that are deemed contractual termination benefits, which the Registrants recorded during the second quarter of 2012.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three months ended March 31, 2013 and March 31, 2012, the Registrants recorded the following severance benefits costs associated with the identified job reductions within operating and maintenance expense in their Consolidated Statements of Operations, except for ComEd and BGE:

Three Months Ended March 31, 2013 **Severance Benefits(a)**	**Exelon**	**Generation**	**ComEd(b)**	**PECO**	**BGE(c)**
Severance charges	$ 2	$ 2	$	$	$
Stock compensation	1	1			
Total severance benefits	$ 3	$ 3	$	$	$

Three Months Ended March 31, 2012 **Severance Benefits(a)**	**Exelon**	**Generation**	**ComEd(b)**	**PECO**	**BGE(c)**
Severance charges	$ 67	$ 35	$ 9	$ 3	$ 14
Stock compensation	8	5	1	1	1
Other charges	8	5	1	1	1
Total severance benefits	$ 83	$ 45	$ 11	$ 5	$ 16

(a) The amounts above include $3 million and $29 million at Generation, $0 million and $11 million at ComEd, $0 million and $5 million at PECO, and $0 million and $5 million at BGE, for amounts billed by BSC through intercompany allocations for the three months ended March 31, 2013 and 2012, respectively.
(b) ComEd established regulatory assets of $0 million and $11 million for severance benefits costs for the three months ended March 31, 2013 and 2012, respectively. The majority of these costs are expected to be recovered over a five-year period.
(c) BGE established regulatory assets of $0 million and $16 million for severance benefits costs for the three months ended March 31, 2013 and 2012, respectively. The majority of these costs are being recovered over a five-year period beginning in March 2013.

Amounts included in the table below represent the severance liability recorded by Exelon, Generation, ComEd, PECO and BGE for employees of those Registrants and exclude amounts billed through intercompany allocations:

Three Months Ended March 31, 2013 **Severance liability**	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**
Balance at December 31, 2012	$ 111	$ 33	$ 1	$	$ 11
Severance charges(a)	2				
Stock compensation	1				
Payments	(22)	(8)			(2)
Balance at March 31, 2013	$ 92	$ 25	$ 1	$	$ 9

Three Months Ended March 31, 2012 **Severance liability**	**Exelon**	**Generation**	**ComEd**	**PECO**	**BGE**

Balance at December 31, 2011	$	$	$	$	$
Severance charges(a)	67	13			11
Stock compensation	8	2			
Other charges(b)	8	1			
Balance at March 31, 2012	$ 83	$ 16	$	$	$ 11

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(a) Includes salary continuance and health and welfare severance benefits. Amounts represent ongoing severance plan benefits. Amounts also include one-time termination benefits of $1 million and $0 million for Exelon and Generation, respectively, as of March 31, 2013, which they began to recognize in the second quarter of 2012.
(b) Primarily includes life insurance, employer payroll taxes, educational assistance, and outplacement services.

Cash payments under the plan began in the second quarter of 2012. Substantially all cash payments under the plan are expected to be made by the end of 2016.

Pro-forma Impact of the Merger

The following unaudited pro forma financial information reflects the consolidated results of operations of Exelon and Generation as if the merger with Constellation had taken place on January 1, 2011. The unaudited pro forma information was calculated after applying Exelon s and Generation s accounting policies and adjusting Constellation s results to reflect purchase accounting adjustments.

The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of results of operations that would have been achieved had the merger events taken place on the dates indicated, or the future consolidated results of operations of the combined company.

	Three Months Ended March 31, 2012	
	Generation	Exelon
Total Revenues	$ 3,997	$ 6,977
Net income attributable to Exelon	129	409
Basic Earnings Per Share	n.a.	$ 0.48
Diluted Earnings Per Share	n.a.	0.48

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 of the Exelon 2012 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). EIMA provides a structure for substantial capital investment by utilities over a ten-year period to modernize Illinois electric utility infrastructure. EIMA allows for the recovery of costs by a utility through a pre-established performance-based formula rate tariff, approved by the ICC.

On April 1, 2013, ComEd filed annual progress reports on both its Infrastructure Investment Plan and AMI Implementation Plan as required by statute. On April 9, 2013, the ICC initiated an investigation proceeding pursuant to the provisions of EIMA to review ComEd s progress in implementing the AMI Plan. The ICC s Order in this proceeding is expected by June 30, 2013.

On April 29, 2013, ComEd filed its 2013 distribution formula rate update, which establishes the net revenue requirement used to set the rates that will take effect in January 2014 after the ICC s review. The revenue requirement requested in the filing is based on 2012 actual costs and forecasted 2013 capital additions as well as

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an annual reconciliation of the revenue requirement in effect in 2012 to the actual costs incurred for that year. ComEd requested a total increase to the net revenue requirement of $311 million, reflecting an increase of $169 million for the initial revenue requirement for 2013 and an increase of $142 million for the annual reconciliation for 2012. The initial revenue requirement for 2013 provided for a weighted average debt and equity return on distribution rate base of 6.99% inclusive of an allowed return on common equity of 8.72%, reflecting the average rate on 30-year treasury notes plus 580 basis points. The annual reconciliation for 2012 provided for a weighted average debt and equity return on distribution rate base of 7.01% inclusive of an allowed return on common equity of 8.72%, reflecting the average rate on 30-year treasury notes plus 580 basis points.

Rates effective in 2013 as a result of the 2012 distribution formula rate update are subject to a reconciliation to actual 2013 costs, which will be filed with the ICC in 2014. The approved annual reconciliation amount will be reflected in customer rates beginning in January 2015. 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 in effect and its best estimate of the probable increase or decrease in the revenue requirement expected to ultimately be approved by the ICC in that year s reconciliation proceedings based on the year s actual costs incurred.

As of March 31, 2013, and December 31, 2012, ComEd recorded a net regulatory asset associated with the distribution formula rate of $255 million and $209 million, respectively.

Senate Bill 9 and House Bill 2529 (Exelon and ComEd). During March 2013, the Illinois House and Senate each passed Senate Bill 9 with supermajority votes to clarify the intent of EIMA on three major issues: the use of year-end rather than average rate base and capital structure in the annual reconciliation, the use of ComEd s weighted average cost of capital interest rate to apply to the annual reconciliation and an allowed return on ComEd s pension asset. These major issues were also addressed in ComEd s appeal of the ICC s May 2012 Order and October 2012 Rehearing Order filed in the Illinois Appellate Court in October 2012. See Note 3 of the Exelon 2012 Form 10-K for further details regarding the appeal. In addition, Senate Bill 9 provides for accelerated AMI deployment that would commence earlier than 2015 as currently approved by the ICC.

On March 21, 2013, Senate Bill 9 was sent to the Illinois Governor for his consideration. The Illinois Governor vetoed the legislation on May 5, 2013. ComEd intends to seek legislative override of the Illinois Governor s veto, which requires approved by supermajority votes in each of the Illinois House and Senate. If the legislation becomes law by June 15, 2013, ComEd would also update certain elements of its AMI deployment schedule to provide for an accelerated deployment as called for by Senate Bill 9.

If the legislation is enacted, ComEd projects that Senate Bill 9 would result in increased operating revenues of approximately $25 million and $65 million in 2013 and 2014, respectively. Also, if the legislation is enacted, ComEd projects that Senate Bill 9 would accelerate capital expenditures by approximately $35 million and $40 million in 2013 and 2014, respectively. The April 29, 2013 annual distribution formula rate filing discussed above does not reflect the enactment of Senate Bill 9. If enacted, the distribution formula rate update filing will be revised to reflect the passage of such legislation shortly thereafter.

Illinois Procurement Proceedings (Exelon and ComEd). ComEd is permitted to recover its electricity procurement costs from retail customers without mark-up. The IPA s 2013 procurement plan, approved by the ICC, provides for curtailment of the existing long-term contracts for renewable energy and RECs in response to the increased number of ComEd s customers purchasing their energy from alternative energy suppliers on their own or through municipal aggregation. In March 2013, ICC staff and the IPA approved ComEd s updated load forecast. Purchases under the existing long-term contracts for energy and the associated RECs were reduced

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

under the terms of the contracts for the June 2013 May 2014 period on a pro-rata basis to keep the purchases under the statutory impact cap. The curtailment was applied proportionately to each of the long-term renewable energy suppliers consistent with the terms of the contracts on an equal, pro-rata basis. The curtailment did not have a significant impact on ComEd s financial position or cash flows.

On December 19, 2012, the ICC issued an order directing ComEd and Ameren (the Utilities) to enter into sourcing agreements with FutureGen Industrial Alliance, Inc (FutureGen), under which FutureGen will retrofit and repower an existing plant in Morgan County, Illinois to a 166 MW near zero emissions coal-fueled generation plant, with an assumed commercial operation date in 2017. The proposed term of the agreement is 20 years. The project was approved by the DOE on February 4, 2013. The sourcing agreement is currently being drafted and approved under a separate proceeding, with a final order expected in the second quarter of 2013. The sourcing agreement is expected to stipulate that the Utilities will pay (or receive) the difference between FutureGen s contract prices and the revenues FutureGen receives for capacity and energy from bidding the unit into the MISO markets. The order also directs the Utilities to recover (or pass along) the difference from the Utilities distribution system customers, regardless of whether they purchase electricity from the Utility or from an alternative electric generation supplier. On January 22, 2013, ComEd filed an application for rehearing, requesting the ICC reconsider its December order by expanding the parties to the sourcing agreement to also include RES suppliers. On January 29, 2013, the ICC denied ComEd s rehearing request. ComEd filed an appeal on February 22, 2013, questioning the legality of requiring ComEd to procure power for its non-Eligible Retail Customers. Depending on the precise terms of the sourcing agreement, the eventual market conditions, and the manner of cost recovery, the sourcing agreement could have a material adverse impact on Exelon s and ComEd s cash flows and financial positions.

See Note 17 Commitments and Contingencies for additional information on ComEd s energy commitments.

Pennsylvania Regulatory Matters

Pennsylvania Procurement Proceedings (Exelon and PECO). PECO s current PAPUC approved DSP Program, under which PECO is providing default electric service, has a 29-month term that ends May 31, 2013. 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 will procure electric supply for its default electric customers through five competitive procurements. The load for the residential and small and medium commercial classes will be served through competitively procured fixed price, full requirements contracts of two years or less. Similar to the current DSP Program, for the large commercial and industrial class load, PECO will competitively procure contracts for full requirements default electric generation with the price for energy in each contract set to be the hourly price of the spot market during the term of delivery. In December 2012 and February 2013, PECO entered into contracts with PAPUC-approved bidders, including Generation, for its residential and small and medium commercial classes beginning in June 2013. 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.

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 allow its low-income Customer Assistance Program (CAP) customers to purchase their generation supply from EGSs beginning April 2014. On May 1, 2013, PECO filed its CAP Shopping Plan with the PAPUC.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Smart Meter and Smart Grid Investments (Exelon and PECO). Pursuant to Act 129 and the follow-on Implementation Order of 2009, in April 2010, the PAPUC approved PECO s Smart Meter Procurement and Installation Plan (SMPIP), under which PECO will install more than 1.6 million smart meters and an AMI communication network by 2020. The first phase of PECO s SMPIP included the installation of an AMI communications network and the deployment of 600,000 smart meters to communicate with that network. On January 18, 2013, PECO filed with the PAPUC its universal deployment plan for approval of its proposal to deploy the remainder of the 1.6 million smart meters on an accelerated basis by the end of 2014. In total, PECO currently expects to spend up to $595 million, excluding the cost of the original meters (as further described below), on its smart meter infrastructure and approximately $120 million on smart grid investments through 2014 before considering the DOE reimbursements discussed below. As of March 31, 2013, PECO has spent $262 million and $103 million on smart meter and smart grid infrastructure, respectively, not including the DOE reimbursements received to date.

Pursuant to the ARRA of 2009, PECO and the DOE entered into a Financial Assistance Agreement to extend PECO $200 million in non-taxable SGIG funds of which $140 million relates to smart meter deployment and $60 million relates to smart grid infrastructure. As part of the agreement, the DOE has a conditional ownership interest in qualifying Federally-funded project property and equipment, which is subordinate to PECO s existing mortgage. The SGIG funds are being used to offset the total impact to ratepayers of the smart meter deployment required by Act 129. As of March 31, 2013, PECO has received $161 million of the $200 million in reimbursements. PECO s outstanding receivable from the DOE for reimbursable costs was $8 million as of March 31, 2013, which has been recorded in other accounts receivable, net on Exelon s and PECO s Consolidated Balance Sheets.

On August 15, 2012, PECO suspended installation of smart meters for new customers based on a limited number of incidents involving overheating meters. Following its own internal investigation and additional scientific analysis and testing by independent experts completed after September 30, 2012, PECO announced its decision to resume meter deployment work on October 9, 2012. PECO has replaced the previously installed meters with an alternative vendor s meters. PECO intends to move forward with the alternative meters during universal deployment and continues to evaluate meters from several vendors and may use more than one meter vendor during universal deployment.

Following PECO s decision, as of October 9, 2012 PECO will no longer use the original smart meters. For the meters that will no longer be used the accounting guidance requires that any difference between the carrying value and net realizable value be recognized in the current period s earnings, before considering potential regulatory recovery. The cost of the original meters, including installation and removal costs, owned by PECO was approximately $19 million, net of approximately $16 million of reimbursements from the DOE. PECO is seeking full recovery of all incurred costs related to the original deployment of meters. For amounts not recovered from the vendor, PECO will seek regulatory rate recovery in a future filing with the PAPUC. PECO did not seek recovery of original meter costs in the January 2013 universal deployment filing, as resolution with the vendor is still pending. In November 2012, PECO requested and received approval from the DOE that the original meters continue to be allowable costs. In addition, PECO remains eligible for the full $200 million in SGIG funds.

As of March 31, 2013, PECO believes the amounts incurred for the original meters and related installation and removal costs are probable of recovery based on applicable case law and past precedent on reasonably and prudently incurred costs. As a result, a regulatory asset of $17 million, representing the cost of the original meters, net of accumulated depreciation and DOE reimbursements, was recorded on Exelon s and PECO s Consolidated Balance Sheets. If PECO later determines that the regulatory asset is no longer probable of recovery, PECO would be required to recognize a charge in earnings in the period in which that determination was made.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Energy Efficiency Programs (Exelon and PECO). PECO s PAPUC-approved Phase I EE&C Plan has a four-year term that began on June 1, 2009 and will conclude on May 31, 2013. The Phase I Plan sets forth how PECO will meet the required reduction targets established by Act 129 s EE&C provisions, which include a 3% reduction in electric consumption in PECO s service territory and a 4.5% reduction in PECO s annual system peak demand in the 100 hours of highest demand by May 31, 2013. The peak demand period ended on September 30, 2012 and PECO communicated its compliance with the reduction targets in a preliminary report with the PAPUC on March 1, 2013. The final compliance report is due to the PAPUC by November 15, 2013.

On March 29, 2013, PECO filed a Petition with the PAPUC to change the recovery period of certain Direct Load Control (DLC) Program costs necessary to implement the Phase I Plan. The Petition seeks approval to allow PECO to recover $12 million in equipment, installation and information technology costs for its Residential DLC program with the amounts collected for the Phase I Plan. As the Phase I Plan was implemented at a cost less than originally budgeted, PECO proposes to recover these expenses from its Phase I Energy Efficiency Program Charge over-collection consistent with PAPUC guidance to recover all Phase I costs through Phase I funding. The PAPUC approved PECO s Petition on May 9, 2013.

The PAPUC issued its Phase II EE&C implementation order on August 2, 2012, that provides energy consumption reduction requirements for the second phase of Act 129 s EE&C programs, which will go into effect on June 1, 2013. The PAPUC deferred a decision on peak demand reduction requirements until mid-2013. On February 28, 2013, the PAPUC approved PECO s three-year EE&C Phase II plan that was filed on November 1, 2012, and sets forth how PECO will reduce electric consumption by at least 2.9% in its service territory for the period June 1, 2013 through May 31, 2016.

On March 15, 2013, PECO filed a Petition for Approval to Amend its EE&C Phase II Plan to continue its DLC demand reduction program for mass market customers from June 1, 2013 to May 31, 2014. PECO proposed to fund the estimated $10 million cost of the one-year program by modifying incentive levels for other Phase II programs. On May 9, 2013, the PAPUC approved PECO s amended EE&C Phase II plan. The costs of DLC program will be recovered through PECO s Energy Efficiency Program Charge along with all other Phase II Plan costs.

Investigation of Pennsylvania Retail Electricity Market (Exelon and PECO). On July 28, 2011, the PAPUC issued an order outlining the next steps in its investigation into the status of competition in Pennsylvania s retail electric market. The PAPUC found that the existing default service model presents substantial impediments to the development of a vibrant retail market in Pennsylvania and directed its Office of Competitive Markets Oversight to evaluate potential intermediate and long-term structural changes to the default service model. On March 1, 2012, the PAPUC issued the final order describing more detailed recommendations to be implemented prior to the expiration of the electric distribution company s current default service plan and providing guidelines for electric distribution companies for development of their next default service plan. On October 12, 2012, the PAPUC approved PECO s second DSP Program, which includes several new programs to continue PECO s support of retail market competition in Pennsylvania in accordance with the order issued by the PAPUC on December 15, 2011. Further, the PAPUC issued a final order on February 14, 2013, outlining its proposed end-state for default service, which included default service pricing for residential and small commercial customers based on three month full requirements contracts, full requirement contracts using hourly spot market pricing for large commercial and industrial default service customers, and the inclusion of CAP customers in the customer choice programs.

Pennsylvania Act 11 of 2012 (Exelon and PECO). On February 13, 2012, Act 11 was signed into law by the Governor. Act 11 seeks to clarify the PAPUC s authority to approve alternative ratemaking mechanisms, which would allow 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

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

distribution systems in Pennsylvania. Act 11 also includes a provision that allows utilities to use a fully projected future test year under which the PAPUC may permit the inclusion of projected capital costs in rate base for assets that will be placed in service during the first year rates are in effect. The PAPUC s implementation order requires a utility to have a Long Term Infrastructure Improvement Plan (LTIIP) which outlines how the utility is planning to increase its investment for repairing, improving, or replacing aging infrastructure, approved by the Commission prior to implementing a DSIC. On May 9, 2013, the PAPUC approved PECO s LTIIP for its Gas Operations which was filed on February 8, 2013.

Maryland Regulatory Matters

Smart Meter and Smart Grid Investments (Exelon and BGE). In August 2010, the MDPSC approved a comprehensive smart grid initiative for BGE that includes the planned installation of 2 million residential and commercial electric and gas smart meters at an expected total cost of $480 million. 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, 2013 and December 31, 2012, BGE recorded a regulatory asset of $37 million and $31 million, respectively, representing incremental costs, depreciation and amortization, and a debt return on fixed assets related to its AMI program given that it believes such costs are probable of recovery in future rates. Additionally, the MDPSC has determined that the cost recovery for the non-AMI meters that BGE retires will be considered in a future depreciation proceeding. The MDPSC continues to evaluate the impacts of a customer opt-out feature in BGE s Smart Grid program. The ultimate resolution related to this feature could affect BGE s ability to demonstrate cost-effectiveness of the advanced metering system. Pursuant to the ARRA of 2009, BGE is a recipient of $200 million in federal funding from the DOE for its smart grid and other related initiatives, which substantially reduces the total cost of these initiatives to BGE s ratepayers. The project to install the smart meters began in late April 2012.

As of March 31, 2013, BGE had received $162 million in reimbursements from the DOE. As of March 31, 2013, BGE s outstanding receivable from the DOE for reimbursable costs was $13 million, which has been recorded in other accounts receivable, net on Exelon s and BGE s Consolidated Balance Sheets.

Reliability and Quality of Service Standards (Exelon and BGE). During its 2011 legislative session, the Maryland General Assembly passed legislation:

- directing the MDPSC to enact service quality and reliability regulations by July 1, 2012 relating to the delivery of electricity to retail electric customers,
- increasing existing penalties for failure to meet these and other MDPSC regulations, and
- directing the MDPSC to undertake certain studies addressing utility liability for certain customer damages, electric utility service restoration plans, and modifications to existing revenue decoupling mechanisms for extended service interruptions.

In May 2011, the Governor of Maryland signed this legislation into law. The related new service quality and reliability regulations became effective on May 28, 2012. These regulations are still being implemented and could have a material impact on BGE s financial results of operations, cash flows and financial position.

New Electric Generation (Exelon, Generation and BGE). On April 12, 2012, the MDPSC issued an order directing BGE and two other Maryland utilities to enter into a contract for differences (CfD) with CPV Maryland, LLC (CPV), under which CPV will construct an approximately 700 MW natural gas-fired combined-cycle generation plant in Waldorf, Maryland, that it projected will be in commercial operation by June 1, 2015. The initial term of the proposed contract is 20 years. The CfD mandates that the utilities pay (or receive) the difference

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

between CPV s contract prices and the revenues CPV receives for capacity and energy from clearing the unit in the PJM capacity market. The three Maryland utilities are required to enter into a CfD in amounts proportionate to their relative SOS load as of the date of execution. On April 27, 2012, a civil complaint was filed in the United States District Court for the District of Maryland by certain unaffiliated parties that challenges the actions taken by the MDPSC on federal law grounds. Among other requests for relief, the plaintiffs seek to enjoin the MDPSC from executing or otherwise putting into effect any part of its order. The MDPSC and CPV filed motions to dismiss the federal lawsuit, which were both denied by the U.S. District Court on August 3, 2012. Trial of this matter occurred in March 2013, and a decision from the trial judge is now pending. On May 4, 2012, BGE filed a petition in the Circuit Court for Anne Arundel County, Maryland, seeking judicial review of the MDPSC order. That petition was subsequently transferred to the Circuit Court for Baltimore City, where similar appeals have been filed by other interested parties. All cases have now been consolidated and will be heard together by the Circuit Court for Baltimore City pending the outcome of the underlying MDPSC proceeding.

On April 16, 2013, the MDPSC issued an order that required BGE to execute a contract with CPV within 20 days of the date of the order, and BGE executed the contract on May 6, 2013. As of March 31, 2013, there is no impact on Exelon s and BGE s results of operations, cash flows and financial positions. Furthermore, the agreement does not become effective until the resolution of certain items, including all current litigation.

Depending on the ultimate outcome of the pending litigation, on the eventual market conditions and on the manner of cost recovery as of the effective date of the agreement, the CfD could have a material impact on Exelon s and BGE s results of operations, cash flows and financial positions.

Exelon believes that this and other states projects may have artificially suppressed capacity prices in PJM and may continue to do so in future auctions to the detriment of Exelon s market driven position. In addition to this litigation, Exelon is working with other market participants to implement market rules that will appropriately limit the market suppressing effect of such state activities.

2012 Maryland Electric and Gas Distribution Rate Case (Exelon and BGE). On July 27, 2012, BGE filed an application for increases to its electric and gas base rates with the MDPSC. On February 22, 2013, the MDPSC issued an order in BGE s 2012 electric and natural gas distribution rate case for increases in annual distribution service revenue of $81 million and $32 million, respectively. The electric distribution rate increase was set using an allowed return on equity of 9.75% and the gas distribution rate increase was set using an allowed return on equity of 9.60%. The approved electric and natural gas distribution rates became effective for services rendered on or after February 23, 2013. As part of the rate order, the MDPSC approved both recovery of and return on merger integration costs, including severance. As a result, the order affirmed the treatment of $20 million of severance-related costs that BGE had recorded as a regulatory asset in 2012, consistent with prior MDPSC decisions. Additionally, BGE established a new regulatory asset of $8 million related to non-severance-related merger integration costs as of March 31, 2013, which includes $6 million of costs incurred during 2012. These merger integration regulatory assets are recovered over a five year period.

MDPSC Derecho Storm Order (Exelon and BGE). Following the June 2012 Derecho storm which hit the mid-Atlantic region interrupting electrical service to a significant portion of the State of Maryland, the MDPSC issued an order on February 27, 2013 that requires BGE and other Maryland utilities to file several comprehensive reports on improving reliability and grid resiliency that are due at various times before August 30, 2013. BGE cannot predict the outcome of this review, which may result in increased capital expenditures and operating costs. BGE currently expects that any increased capital expenditures and operating costs would be recoverable in distribution rates.

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

The Maryland Strategic Infrastructure Development and Enhancement Program (Exelon and BGE). In February 2013, the Maryland General Assembly passed legislation intended to accelerate gas infrastructure replacements in Maryland by establishing a mechanism for gas companies to promptly recover reasonable and prudent costs of eligible infrastructure replacement projects separate from base rate proceedings. On May 2, 2013, the Governor of Maryland signed the legislation into law; the law takes 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 a cap on the monthly surcharge to residential customers, which effectively caps the surcharge for other 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.

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 s most recent annual formula rate update filed in April 2013 reflects 2012 actual costs plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $488 million plus a $25 million adjustment related to the reconciliation of 2012 actual costs for a net revenue requirement of $513 million. This compares to the May 2012 updated revenue requirement of $450 million offset by a $5 million reduction related to the reconciliation of 2011 actual costs for a net revenue requirement of $445 million. The increase in the revenue requirement was primarily driven by increased plant investment, higher pension and post-retirement healthcare costs, and higher operating and maintenance costs. The 2013 net revenue requirement will become effective June 1, 2013, and is recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

ComEd s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.70%, a decrease from the 8.91% return previously authorized. The decrease in return was primarily due to lower interest rates on ComEd s long-term debt outstanding. As part of the FERC-approved settlement of ComEd s 2007 transmission rate case, the rate of return on common equity is 11.5% and the common equity component of the ratio used to calculate the weighted average debt and equity return for the formula transmission rate is currently capped at 55%.

BGE s most recent annual formula rate update filed in April 2013 reflects actual 2012 expenses and investments plus forecasted 2013 capital additions. The update resulted in a revenue requirement of $158 million offset by a $1 million reduction related to the reconciliation of 2012 actual costs for a net revenue requirement of $157 million. This compares to the April 2012 updated revenue requirement of $156 million increased by $2 million related to the reconciliation of 2011 actual costs for a net revenue requirement of $158 million. The decrease in the revenue requirement was primarily driven by a lower authorized rate of return and reduced rate base, offset partially by higher depreciation and operating and maintenance costs. The 2013 net revenue requirement will become effective June 1, 2013, and is recovered over the period extending through May 31, 2014. The regulatory asset associated with the true-up is being amortized as the associated amounts are recovered through rates.

BGE s updated formula transmission rate currently provides for a weighted average debt and equity return on transmission rate base of 8.35%, a decrease from the 8.43% return previously authorized. The decrease in return was primarily due to a debt issuance in 2012 and lower interest rates on BGE s debt outstanding. As part

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of the FERC-approved settlement in 2006 of BGE s 2005 transmission rate case and updated by FERC s November 2007 order in BGE s 2007 incentive rate filing, the base rate of return on common equity for BGE s electric transmission business is 11.3%.

FERC Transmission Complaint (Exelon and BGE). On February 27, 2013, consumer advocates and regulators from the District of Columbia, New Jersey, Delaware and Maryland, and the Delaware Electric Municipal Cooperatives (the parties), filed a complaint at FERC against BGE and the Pepco Holdings, Inc. companies relating to their respective transmission formula rates. BGE s formula rate includes a 10.8% base rate of return on common equity for most investments included in its rate base. 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 earliest date from which the base return on equity 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. As of March 31, 2013, BGE cannot predict the likelihood or a reasonable estimate of the amount of a change, if any, in the allowed base ROE, or a reasonable estimate of the refund period start date. While BGE cannot predict the outcome of this matter, if FERC orders a reduction of BGE s base ROE to 8.7%, the annual impact would be a reduction in revenues of approximately $10 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. 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. After FERC ultimately denied all requests for rehearing on all issues, several parties filed petitions in the U.S. Court of Appeals for the Seventh Circuit for review of the decision. On August 6, 2009, that court issued its decision affirming FERC s order with regard to the costs of existing facilities but reversing and remanding to FERC for further consideration its decision with regard to the costs of new facilities 500 kV and above. On January 21, 2010, FERC issued an order establishing paper hearing procedures to supplement the record. On March 30, 2012, FERC issued an order on remand affirming the cost allocation in its April 2007 order. On March 22, 2013, FERC issued an order denying rehearing and made it clear that the cost allocation at issue concerns only projects approved prior to February 1, 2013. A number of entities have filed appeals of the FERC orders. 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.

On October 11, 2012, the PJM Transmission Owners filed with FERC a cost allocation for new transmission facilities asking that the new cost allocation methodology apply to all transmission approved by the PJM Board on or after February 1, 2013. The proposed methodology is a hybrid methodology that would socialize 50% of the costs of new facilities at 500kV and above and double-circuit 345kV lines, and allocate the remaining 50% to

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direct beneficiaries. For all other facilities, the costs would be allocated to the direct beneficiaries. On March 22, 2013, FERC issued an order accepting the cost allocation with minor exceptions and requiring a compliance filing on those few issues within 120 days of the order.

PJM Minimum Offer Price Rule (Exelon and Generation). PJM s capacity market rules include a Minimum Offer Price Rule (MOPR) that is intended to preclude sellers from artificially suppressing the competitive price signals for generation capacity. The proceedings leading to the FERC s approval of the existing MOPR were extensive. The parties disputed numerous elements of the MOPR including: (i) the default price that should apply to bids found subject to the MOPR, (ii) the duration of the MOPR and (iii) the application of the MOPR to self-supplying capacity and state-sponsored capacity. The FERC orders approving the existing MOPR have been appealed to the Third Circuit Court of Appeals. A resolution of that appeal is not expected until sometime in late 2013.

In May 2012, PJM announced the results of its capacity auction covering 2015 and 2016. Several new units with state-sanctioned subsidy contracts cleared in the auction at prices below the MOPR. Potentially, states will expand such state-sanctioned subsidy programs or other states may seek to establish similar programs. Generation believes that further revisions to the MOPR are necessary to ensure that the potential to artificially reduce capacity auction prices is appropriately limited in PJM. In late December 2012, PJM filed a new MOPR for approval at the FERC, which Exelon believed would be more effective in preventing state-sanctioned subsidy contracts from artificially reducing capacity prices. Generation was actively involved in the process through which the MOPR changes were developed and supported the changes. On February 5, 2013, the FERC issued a letter finding that PJM s new MOPR filing is deficient and requested that PJM provide additional information on several aspects of PJM s MOPR proposal. In early March 2013, PJM filed the additional information requested by the FERC. On May 3, 2013, the FERC issued its order. While the FERC order accepted certain aspects of the proposal that Exelon supported (such as applying the MOPR to all of PJM and not just certain zones within PJM), the FERC required PJM to retain a key element of its previous MOPR structure, the unit-specific exemption, an element that Exelon had supported removing. Exelon is currently considering its options with respect to this proceeding.

Market Based Rates (Exelon, Generation, ComEd, PECO and BGE). Generation, ComEd, PECO and BGE are public utilities for purposes of the Federal Power Act and are required to obtain FERC s acceptance of rate schedules for wholesale electricity sales. Currently, Generation, ComEd, PECO and BGE have authority to execute wholesale electricity sales at market-based rates. As is customary with market-based rate schedules, FERC has reserved the right to suspend market-based rate authority on a retroactive basis if it subsequently determines that Generation, ComEd, PECO or BGE has violated the terms and conditions of its tariff or the Federal Power Act. FERC is also authorized to order refunds in certain instances if it finds that the market-based rates are not just and reasonable under the Federal Power Act.

As required by FERC s regulations, as promulgated in the Order No. 697 series, Generation, ComEd, PECO and BGE have filed market power analyses using the prescribed market share screens to demonstrate that Generation, ComEd, PECO and BGE qualify for market-based rates in the regions where they are selling energy and capacity under market-based rate tariffs. These analyses must examine historic test period data and must be updated every three years on a prescribed schedule. The most recent updated analysis for the PJM and Northeast Regions was filed in late 2010, based on 2009 historic test period data. On June 22, 2011, FERC issued an order confirming Generation s continued authority to charge market based rates, based on Generation s most recent updated analysis filed in 2010, stating that any market power concerns are adequately addressed by PJM s monitoring and mitigation programs. Similarly, on June 29, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the Central Region which the FERC accepted on November 13, 2012, and on December 23, 2011, Generation filed its updated market power analysis for the Southeast Region which

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the FERC accepted on October 10, 2012. On December 21, 2012, Generation, ComEd, BGE and PECO filed their updated market power analysis for the SPP region, and the FERC has not yet acted on this filing.

Reliability Pricing Model (Exelon, Generation and BGE). PJM s RPM auctions take place 36 months ahead of the scheduled delivery year. The most recent auction for the delivery year ending May 31, 2016 occurred in May 2012.

License Renewals (Exelon and Generation). On June 22, 2011, Generation submitted applications to the NRC to extend the operating licenses of Limerick Units 1 and 2 by 20 years. The current operating licenses for Limerick Units 1 and 2 expire in 2024 and 2029, respectively. In June 2012, the United States District Court of Appeals for the DC Circuit vacated the NRC s temporary storage rule on the grounds that the NRC should have conducted a more comprehensive environmental review to support the rule. The temporary storage rule (also referred to as the waste confidence decision) recognizes that licensees can safely store spent nuclear fuel at nuclear plants for up to 60 years beyond the original and renewed licensed operating life of the plants and that licensing renewal decisions do not require discussion of the environmental impact of spent fuel stored on site. In August 2012, the NRC placed a hold on issuing new or renewed operating licenses that depend on the temporary storage rule until the court s decision is addressed. In September 2012, the NRC directed NRC Staff to revise the temporary storage rule through rulemaking no later than September 6, 2014. Generation does not expect the NRC to issue license renewals until the end of 2014, at the earliest.

On August 29, 2012 and August 30, 2012, Generation submitted hydroelectric license applications to the FERC for 46-year licenses for the Conowingo Hydroelectric Project (Conowingo) and the Muddy Run Pumped Storage Facility Project (Muddy Run), respectively. Generation is working with stakeholders to resolve licensing issues, including: (1) water quality, (2) fish passage and habitat, and (3) sediment. In the third quarter 2013, Exelon expects to file a water quality certification application pursuant to Section 401 of the Clean Water Act with the MDE for Conowingo, and a water quality certification application pursuant to Section 401 of the Clean Water Act with the PA DEP for Muddy Run, addressing these and other issues. The stations are being depreciated over their useful lives, which includes the license renewal period. Although Generation expects that these licenses will be renewed, it cannot predict the conditions that may be imposed. Resolution of these issues may require a substantial increase in capital expenditures or may result in increased operating costs and significantly affect Generation s results of operations or financial position. Based on the latest FERC procedural schedule, the FERC licensing process is not expected to be completed prior to the expiration of Muddy Run s current license on August 31, 2014, and the expiration of Conowingo s license on September 1, 2014. However, the stations would continue to operate under annual licenses until FERC takes action on the 46-year license applications.

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

Exelon, ComEd, PECO and BGE 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.

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The following tables provide information about the regulatory assets and liabilities of Exelon, ComEd, PECO and BGE as of March 31, 2013 and December 31, 2012. For additional information on the specific regulatory assets and liabilities, refer to Note 3 of the Exelon 2012 Form 10-K.

March 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 308	$ 3,685	$	$	$	$	$	$
Deferred income taxes	14	1,397	5	63		1,269	9	65
AMI programs	3	81	3	16		28		37
AMI meter events		17				17		
Under-recovered distribution service costs	52	203	52	203				
Debt costs	13	65	10	60	3	5	1	9
Fair value of BGE long-term debt(b)		245						
Fair value of BGE supply contract(c)	61	9						
Severance	29	23	25	6			4	17
Asset retirement obligations		92		67		25		
MGP remediation costs	56	223	49	189	6	32	1	2
RTO start-up costs	3	2	3	2				
Under-recovered uncollectible accounts	6		6					
Under-recovered electric universal service fund costs	4				4			
Financial swap with Generation			85					
Renewable energy and associated RECs	15	60	15	60				
Under-recovered energy and transmission costs	32		32					
DSP Program costs	1	3			1	3		
DSP II Program costs	2	2			2	2		
Deferred storm costs	3	5					3	5
Electric generation-related regulatory asset	13	40					13	40
Rate stabilization deferral	67	209					67	209
Energy efficiency and demand response programs	49	129					49	129
Merger integration costs(d)	1	7					1	7
Other	33	24	16	15	17	8		2
Total regulatory assets	$ 765	6,521	$ 301	$ 681	$ 33	$ 1,389	$ 148	$ 522

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

March 31, 2013	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,530	$	$ 2,138	$	$ 392	$	$
Removal costs	98	1,417	77	1,199			21	218
Energy efficiency and demand response programs	145		43		102			
Electric distribution tax repairs	20	125			20	125		
Gas distribution tax repairs	8	43			8	43		
Over-recovered uncollectible accounts								
Over-recovered energy and transmission costs	85		6		71(e)		8(i)	
Over-recovered gas universal service fund costs	3				3			
Over-recovered AEPS costs	1				1			
Revenue subject to refund(f)	40		40					
Over-recovered electric and gas revenue decoupling(g)	15						15	
Other	3						3	
Total regulatory liabilities	$ 418	$ 4,115	$ 166	$ 3,337	$ 205	$ 560	$ 47	$ 218

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory assets								
Pension and other postretirement benefits(a)	$ 304	$ 3,673	$	$	$	$	$	$
Deferred income taxes	14	1,382	5	62		1,255	9	65
AMI programs	3	70	3	10		29		31
AMI meter events		17				17		
Under-recovered distribution service costs	18	191	18	191				
Debt costs	14	68	11	62	3	6	1	9
Fair value of BGE long-term debt(b)		256						
Fair value of BGE supply contract(c)	77	12						
Severance	29	28	25	12			4	16
Asset retirement obligations		90		65		25		
MGP remediation costs	58	232	51	197	6	33	1	2
RTO start-up costs	3	2	3	2				
Under-recovered electric universal service fund costs	11				11			
Financial swap with Generation			226					
Renewable energy and associated RECs	18	49	18	49				
Under-recovered energy and transmission costs	43		14		1(h)		28(i)	
DSP Program costs	1	3			1	3		
DSP II Program costs	1	2			1	2		
Deferred storm costs	3	6					3	6
Electric generation-related regulatory asset	16	40					16	40
Rate stabilization deferral	67	225					67	225
Energy efficiency and demand response programs	56	126					56	126
Under-recovered electric revenue decoupling(g)	5						5	
Other	23	25	14	16	9	8		2

Total regulatory assets	$ 764	$ 6,497	$ 388	$ 666	$ 32	$ 1,378	$ 190	$ 522

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

December 31, 2012	Exelon		ComEd		PECO		BGE	
	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent	Current	Noncurrent
Regulatory liabilities								
Nuclear decommissioning	$	$ 2,397	$	$ 2,037	$	$ 360	$	$
Removal costs	97	1,406	75	1,192			22	214
Energy efficiency and demand response programs	131		43		88			
Electric distribution tax repairs	20	132			20	132		
Gas distribution tax repairs	8	46			8	46		
Over-recovered uncollectible accounts	6		6					
Over-recovered energy and transmission costs	54		6		48(e)			
Over-recovered gas universal service fund costs	3				3			
Over-recovered AEPS costs	2				2			
Revenue subject to refund(f)	40		40					
Over-recovered gas revenue decoupling(g)	7						7	
Total regulatory liabilities	$ 368	$ 3,981	$ 170	$ 3,229	$ 169	$ 538	$ 29	$ 214

(a) Pension and other postretirement benefit regulatory assets include a regulatory asset established at the date of the merger related to BGE s portion of the deferred costs associated with legacy Constellation s pension and other postretirement benefit plans. That BGE-related regulatory asset is being amortized over a period of approximately 12 years, which generally represents the expected average remaining service period of plan participants at the date of the merger.
(b) Represents the regulatory asset recorded at Exelon Corporate for the difference in the fair value of the long-term debt of BGE as of the merger date.
(c) Represents the regulatory asset recorded at Exelon Corporate representing the fair value of BGE s supply contracts as of the close of the merger date. BGE is allowed full recovery of the costs of its electric and gas supply contracts through approved, regulated rates.
(d) Relates to integration costs to achieve distribution synergies related to the merger transaction.
(e) Includes $39 million related to the over-recovered electric supply costs under the GSA, $26 million related to the over-recovered natural gas costs under the PGC and $6 million related to over-recovered electric transmission costs as of March 31, 2013. As of December 31, 2012, includes $47 million related to the over-recovered electric supply costs under the GSA and $1 million related to the over-recovered natural gas costs under the PGC.
(f) Primarily represents the regulatory liability for revenue subject to refund recorded pursuant to the ICC s order in the 2007 Rate Case. See Note 3 of Exelon s 2012 Form 10-K for additional information regarding the 2007 Rate Case.
(g) Represents the electric and gas distribution costs recoverable from or refundable to customers under BGE s decoupling mechanism. As of March 31, 2013, includes $5 million of over-recovered electric distribution costs and $10 million of over-recovered gas distribution costs under BGE s decoupling mechanism. As of December 31, 2012, relates to $5 million of under-recovered electric distribution costs and $7 million of over-recovered gas distribution costs under BGE s decoupling mechanism.
(h) Relates to under-recovered transmission costs.
(i) Relates to $8 million of over-recovered natural gas supply costs as of March 31, 2013. As of December 31, 2012, includes to $9 million of under-recovered electric supply costs and $19 million of under-recovered natural gas supply costs.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

ComEd, PECO and BGE are required, under separate legislation and regulations in Illinois, Pennsylvania and Maryland, respectively, to purchase certain receivables from retail electric and natural gas suppliers. For retail suppliers participating in the utilities consolidated billing, ComEd, PECO and BGE must purchase their customer accounts receivables. ComEd and BGE purchase receivables at a discount to primarily recover 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 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, 2013 and December 31, 2012.

As of March 31, 2013	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 244	$ 86	$ 69	$ 89
Allowance for uncollectible accounts(b)	(25)	(13)	(7)	(5)
Purchased receivables, net	$ 219	$ 73	$ 62	$ 84

As of December 31, 2012	Exelon	ComEd	PECO	BGE
Purchased receivables(a)	$ 191	$ 55	$ 65	$ 71
Allowance for uncollectible accounts(b)	(21)	(9)	(6)	(6)
Purchased receivables, net	$ 170	$ 46	$ 59	$ 65

(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 s total equity in earnings (losses) on the investment in CENG is as follows:

	Three Months Ended March 31, 2013	For the Period March 12, through March 31, 2012
Equity investment income (loss)	$ 15	$ (9)
Amortization of basis difference in CENG	(27)	(12)

Total equity in losses	CENG	$ (12)	$ (21)

As of March 12, 2012, Generation had an initial basis difference of approximately $204 million between the initial carrying value of its investment in CENG and its underlying equity in CENG. This basis difference resulted from the requirement to record the investment in CENG at fair value under purchase accounting while the underlying assets and liabilities within CENG continue to be accounted for on a historical cost basis. Generation is amortizing this basis difference over the respective useful lives of the assets and liabilities of CENG or as those assets and liabilities impact the earnings of CENG.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

In future periods, Generation may be eligible for distributions from its investment in CENG in excess of its 50.01% ownership interest based on tax sharing provisions contained in the operating agreement for CENG. Through purchase accounting, Generation recorded the fair value of expected future distributions. Generation will record these distributions when realized as a reduction in its investment in CENG. Distributions realized in excess of the fair value recorded would be recorded in earnings in the period earned.

Related Party Transactions (Exelon and Generation)

CENG

A wholly-owned subsidiary of Generation has an agreement under which it is purchasing 85% of the output of CENG s nuclear plants that is not sold to third parties under pre-existing firm and unit contingent PPAs through 2014. Beginning on January 1, 2015 and continuing to the end of the life of the respective plants, Generation will purchase on a unit contingent basis 50.01% of the output of CENG s nuclear plants, and EDF will purchase on a unit contingent basis 49.99% of the output.

In addition to the PPA, a subsidiary of Generation has a power services agency agreement (PSAA) with the CENG plants, which expires on December 31, 2014. The PSAA is a five-year agreement under which Generation provides scheduling, asset management and billing services to the CENG plants for a specified monthly fee. The charges for services reflect the cost of the service.

In addition to the PSAA, Exelon has a shared services agreement (SSA) with CENG, which expires in 2017. Pursuant to an agreement between Exelon and EDF, the pricing in the SSA for services reflect actual costs determined on the same basis that BSC charges its affiliates for similar services subject to an annual cap for most SSA services provided.

The impact of transactions under these agreements on Exelon s and Generation s Consolidated Financial Statements is summarized below:

Agreement	Income/(Expense) Three Months Ended March 31, 2013	Income/(Expense) For the Period March 12 through March 31, 2012	Income Statement Classification	Accounts Receivable/ (Accounts Payable) At March 31, 2013
PPA	$ (248)	$ (35)	Purchased power and fuel	$ (70)
PSAA	1	1	Operating revenues	
SSA	11	3	Operating revenues	4

7. Goodwill (Exelon and ComEd)

Goodwill

Under the authoritative guidance for the accounting for goodwill, ComEd is required to perform an assessment for possible impairment of its goodwill at least annually or more frequently if an event occurs that would more likely than not reduce the fair value of the ComEd reporting unit below its carrying amount. Management concluded the remeasurement of the like-kind exchange position and the charge to ComEd s earnings in the first quarter of 2013 triggered an interim goodwill impairment assessment and, as a result, ComEd tested its goodwill for impairment as of January 31, 2013.

The first step of the interim impairment assessment comparing the estimated fair value of ComEd to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required. Consistent with prior impairment tests, the estimated fair value of ComEd was determined using a

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

weighted combination of a discounted cash flow analysis and a market multiples analysis. The discounted cash flow analysis relies on a single scenario reflecting base case or management s best estimate of projected cash flows for ComEd s business. The discounted cash flow analysis used in the interim goodwill impairment assessment reflected Exelon s indemnity to hold ComEd harmless from any unfavorable impacts of the after-tax interest amounts related to the like-kind exchange position on ComEd s equity.

While the interim assessment indicated no impairment of ComEd s goodwill, certain assumptions used to estimate the fair value of the company are highly sensitive to changes. Adverse regulatory actions such as the early termination of EIMA or changes in significant assumptions, including the discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows from ComEd s business, and the fair value of debt, could potentially result in a future impairment of ComEd s goodwill, which could be material. Based on the results of the interim goodwill test, the estimated fair value of ComEd would have needed to decrease by more than 10 percent for ComEd to fail the first step of the impairment test.

8. 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, trust preferred securities (long-term debt to financing trusts or junior subordinated debentures), and preferred securities as of March 31, 2013 and December 31, 2012:

Exelon

	March 31, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 444	$ 1	$ 443	$	$ 444
Long-term debt (including amounts due within one year)	18,871		20,200	422	20,622
Long-term debt to financing trusts	648			662	662
SNF obligation	1,020		794		794
Preferred securities of subsidiary	87		93		93

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 214	$ 4	$ 210	$	$ 214
Long-term debt (including amounts due within one year)	18,745		20,244	276	20,520
Long-term debt to financing trusts	648			664	664
SNF obligation	1,020		763		763
Preferred securities of subsidiary	87		82		82

Generation

	March 31, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total

Short-term liabilities	$ 13	$	$ 13	$	$ 13
Long-term debt (including amounts due within one year)	7,621		7,621	405	8,026
SNF obligation	1,020		794		794

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$	$	$	$	$
Long-term debt (including amounts due within one year)	7,483		7,591	258	7,849
SNF obligation	1,020		763		763

ComEd

	March 31, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 220	$	$ 220	$	$ 220
Long-term debt (including amounts due within one year)	5,568		6,485	18	6,503
Long-term debt to financing trust	206			213	213

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$	$	$	$	$
Long-term debt (including amounts due within one year)	5,567		6,530	18	6,548
Long-term debt to financing trust	206			212	212

PECO

	March 31, 2013				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 210	$	$ 210	$	$ 210
Long-term debt (including amounts due within one year)	1,948		2,242		2,242
Long-term debt to financing trusts	184			188	188
Preferred securities	87		93		93

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$ 210	$	$ 210	$	$ 210
Long-term debt (including amounts due within one year)	1,947		2,264		2,264
Long-term debt to financing trusts	184			188	188
Preferred securities	87		82		82

BGE

March 31, 2013

	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$	$	$	$	$
Long-term debt (including amounts due within one year)	2,178		2,464		2,464
Long-term debt to financing trusts	258			261	261

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2012				
	Carrying Amount	Fair Value Level 1	Level 2	Level 3	Total
Short-term liabilities	$	$	$	$	$
Long-term debt (including amounts due within one year)	2,178		2,468		2,468
Long-term debt to financing trusts	258			263	263

Short-Term Liabilities. The short-term liabilities included in the tables above are comprised of short-term borrowings (Level 2), short-term notes payable related to PECO s accounts receivable agreement (Level 2), and dividends payable (Level 1). The Registrants carrying amounts of the short-term liabilities are representative of fair value because of the short-term nature of these instruments. See Note 10 Debt and Credit Agreements for additional information on PECO s accounts receivable agreement.

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

Generation has fixed rate project financing debt (Level 3), the fair value of which 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, for certain government-backed debt, 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.

The Registrants also have tax-exempt debt (Level 3). Due to low trading volume in this market, qualitative factors, such as market conditions, investor demand, and circumstances related to the issuer (i.e., political and regulatory environment), may be incorporated into the credit spreads that are used to obtain the fair value as described above.

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

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

Preferred Securities and Junior Subordinated Debentures. The fair value of these securities is determined based on the last closing price prior to quarter end, less accrued interest. The securities are registered with the

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

SEC and are public. On March 25, 2013, PECO issued a notice of redemption for all outstanding series of preferred securities with a redemption date of May 1, 2013. See Note 16 Earnings Per Share and Shareholders Equity for additional information.

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. Financial assets and liabilities utilizing Level 1 inputs include active exchange-traded equity securities, certain exchange-based derivatives, and money market funds.

- 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. Financial assets and liabilities utilizing Level 2 inputs include fixed income securities, non-exchange-based derivatives, commingled and mutual investment funds priced at NAV per fund share and fair value hedges.

- 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. Financial assets and liabilities utilizing Level 3 inputs include infrequently traded non-exchange-based derivatives, investments priced using an alternative pricing mechanism, and middle market lending using third party valuations.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2013.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Exelon

The following tables present assets and liabilities measured and recorded at fair value on Exelon s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and December 31, 2012:

As of March 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents(a)	$ 383	$	$	$ 383
Nuclear decommissioning trust fund investments				
Cash equivalents	216			216
Equity				
Individually held	1,649			1,649
Commingled funds		2,073		2,073
Equity funds subtotal	1,649	2,073		3,722
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,039			1,039
Debt securities issued by states of the United States and political subdivisions of the states		328		328
Debt securities issued by foreign governments		108		108
Corporate debt securities		1,796		1,796
Federal agency mortgage-backed securities		23		23
Commercial mortgage-backed securities (non-agency)		43		43
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		26		26
Fixed income subtotal	1,039	2,335		3,374
Middle market lending			210	210
Other debt obligations		16		16
Nuclear decommissioning trust fund investments subtotal(b)	2,904	4,424	210	7,538
Pledged assets for Zion Station decommissioning				
Cash equivalents		41		41
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	138	10		148
Debt securities issued by states of the United States and political subdivisions of the states		29		29
Corporate debt securities		224		224
Federal agency mortgage-backed securities		29		29
Fixed income subtotal	138	292		430

Middle market lending			104	104
Pledged assets for Zion Station decommissioning subtotal(c)	138	333	104	575
Rabbi trust investments				
Cash equivalents	1			1
Mutual funds(d)(e)	66			66
Rabbi trust investments subtotal	67			67

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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, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity mark-to-market derivative assets				
Economic hedges	801	2,535	554	3,890
Proprietary trading	764	1,637	176	2,577
Effect of netting and allocation of collateral(f)	(1,428)	(3,152)	(572)	(5,152)
Commodity mark-to-market assets subtotal(g)	137	1,020	158	1,315
Interest rate mark-to-market derivative assets		100		100
Effect of netting and allocation of collateral		(43)		(43)
Interest rate mark-to-market derivative assets subtotal		57		57
Other investments	2		9	11
Total assets	3,631	5,834	481	9,946
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(884)	(2,131)	(283)	(3,298)
Proprietary trading	(782)	(1,530)	(187)	(2,499)
Effect of netting and allocation of collateral(f)	1,597	3,216	572	5,385
Commodity mark-to-market liabilities subtotal(g)(h)	(69)	(445)	102	(412)
Interest rate mark-to-market derivative liabilities		(71)		(71)
Effect of netting and allocation of collateral		43		43
Interest rate mark-to-market derivative assets subtotal		(28)		(28)
Deferred compensation		(101)		(101)
Total liabilities	(69)	(574)	102	(541)
Total net assets	$ 3,562	$ 5,260	$ 583	$ 9,405

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents(a)	$ 995	$	$	$ 995
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057

Debt securities issued by states of the United States and political subdivisions of the states	321	321
Debt securities issued by foreign governments	93	93
Corporate debt securities	1,788	1,788
Federal agency mortgage-backed securities	24	24
Commercial mortgage-backed securities (non-agency)	45	45
Residential mortgage-backed securities (non-agency)	11	11
Mutual funds	23	23

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218
Pledged assets for Zion decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89
Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	2			2
Mutual funds(d)(e)	69			69
Rabbi trust investments subtotal	71			71
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	641	4,675
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal(g)	80	1,076	656	1,812
Interest rate mark-to-market derivative assets		114		114
Effect of netting and allocation of collateral		(51)		(51)
Interest rate mark-to-market derivative assets subtotal		63		63
Other Investments	2		17	19

Total assets	4,062	5,778	945	10,785

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(236)	(3,566)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral(f)	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal(g)(h)	(83)	(228)	(289)	(600)
Interest rate mark-to-market derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate mark-to-market derivative liabilities subtotal		(33)		(33)
Deferred compensation		(102)		(102)
Total liabilities	(83)	(363)	(289)	(735)
Total net assets	$ 3,979	$ 5,415	$ 656	$ 10,050

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

(b) Excludes net assets of $21 million and $30 million at March 31, 2013 and December 31, 2012, 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 $5 million and $7 million at March 31, 2013 and December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) The mutual funds held by the Rabbi trusts include $51 million related to deferred compensation and $15 million related to Supplemental Executive Retirement Plan at March 31, 2013, and $53 million related to deferred compensation and $16 million related to Supplemental Executive Retirement Plan at December 31, 2012. These funds are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

(e) Excludes $29 million and $28 million of the cash surrender value of life insurance investments at March 31, 2013 and December 31, 2012, respectively.

(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $169 million, $64 million and $0 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of March 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.

(g) The Level 3 balance does not include current and noncurrent assets for Generation and current and noncurrent liabilities for ComEd of $85 million and $0 million at March 31, 2013 and $226 million and $0 million at December 31, 2012, respectively, related to the fair value of Generation s financial swap contract with ComEd.

(h) The Level 3 balance includes the current and noncurrent liability of $15 million and $60 million at March 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table presents the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013 and 2012:

Three Months Ended March 31, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 367	$ 17	$ 656
Total realized / unrealized losses					
Included in net income	1		(127)(a)		(126)
Included in regulatory assets	1		(8)(b)		(7)
Change in collateral			33		33
Purchases, sales, issuances and settlements					
Purchases(c)	32	22	(5)(c)		49
Sales	(7)	(7)	(4)	(8)	(26)
Transfers into Level 3			4		4
Transfers out of Level 3					
Balance as of March 31, 2013	$ 210	$ 104	$ 260	$ 9	$ 583
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended March 31, 2013	$ 1	$	$ (79)	$	$ (78)

(a) Includes the reclassification of $48 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three months ended March 31, 2013, respectively.
(b) Excludes increases in fair value of $8 million and realized losses reclassified due to settlements of $133 million associated with Generation s financial swap contract with ComEd for the three months ended March 31, 2013, respectively. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

Three Months Ended March 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 17	$	$ 67
Total realized / unrealized gains					
Included in net income			85(a)		85
Included in regulatory assets			(35)		(35)
Change in collateral			(36)		(36)
Purchases, sales, issuances and settlements					
Purchases(c)		6	329	14	349
Sales		(1)			(1)
Transfers out of Level 3			(1)		(1)

Balance as of March 31, 2012	$	13	$	42	$	359	$	14	$	428
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended March 31, 2012	$		$		$	104	$		$	104

(a) Includes the reclassification of $19 million of realized losses due to the settlement of derivative contracts recorded in results of operations for the three months ended March 31, 2012.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) Includes $135 million of increases in fair value and $147 million of realized losses due to settlements during 2012 of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $323 million of fair value from contracts and $14 million of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013 and 2012:

	Operating Revenues	Purchased Power and Fuel
Total gains (losses) included in net income for the three months ended March 31, 2013	$ (159)	$ 32
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2013	$ (117)	$ 38

	Operating Revenues	Purchased Power and Fuel
Total gains (losses) included in net income for the three months ended March 31, 2012	$ 87	$ (2)
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2012	$ 115	$ (11)

Generation

The following tables present assets and liabilities measured and recorded at fair value on Generation s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and December 31, 2012:

As of March 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Cash equivalents	$ 56	$	$	$ 56
Nuclear decommissioning trust fund investments				
Cash equivalents	216			216
Equity				
Individually held	1,649			1,649
Commingled funds		2,073		2,073
Equity funds subtotal	1,649	2,073		3,722
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,039			1,039
Debt securities issued by states of the United States and political subdivisions of the states		328		328
Debt securities issued by foreign governments		108		108
Corporate debt securities		1,796		1,796
Federal agency mortgage-backed securities		23		23
Commercial mortgage-backed securities (non-agency)		43		43
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		26		26

Fixed income subtotal	1,039	2,335		3,374
Middle market lending			210	210
Other debt obligations		16		16
Nuclear decommissioning trust fund investments subtotal(b)	2,904	4,424	210	7,538

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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, 2013	Level 1	Level 2	Level 3	Total
Pledged assets for Zion Station decommissioning				
Cash equivalents		41		41
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	138	10		148
Debt securities issued by states of the United States and political subdivisions of the states		29		29
Corporate debt securities		224		224
Federal agency mortgage-backed securities		29		29
Fixed income subtotal	138	292		430
Middle market lending			104	104
Pledged assets for Zion Station decommissioning subtotal(c)	138	333	104	575
Rabbi trust investments				
Mutual funds (d)(e)	12			12
Rabbi trust investments subtotal	12			12
Commodity mark-to-market derivative assets				
Economic hedges	801	2,535	639	3,975
Proprietary trading	764	1,637	176	2,577
Effect of netting and allocation of collateral(f)	(1,428)	(3,152)	(572)	(5,152)
Commodity mark-to-market assets subtotal(g)	137	1,020	243	1,400
Interest rate mark-to-market derivative assets		88		88
Effect of netting and allocation of collateral		(43)		(43)
Interest rate mark-to-market derivative assets subtotal		45		45
Other investments	2		9	11
Total assets	3,249	5,822	566	9,637
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(884)	(2,131)	(208)	(3,223)
Proprietary trading	(782)	(1,530)	(187)	(2,499)
Effect of netting and allocation of collateral(f)	1,597	3,216	572	5,385
Commodity mark-to-market liabilities subtotal	(69)	(445)	177	(337)

Interest rate mark-to-market derivative liabilities		(71)		(71)
Effect of netting and allocation of collateral		43		43
Interest rate mark-to-market derivative liabilities subtotal		(28)		(28)
Deferred compensation		(26)		(26)
Total liabilities	(69)	(499)	177	(391)
Total net assets	$ 3,180	$ 5,323	$ 743	$ 9,246

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents(a)	$ 487	$	$	$ 487
Nuclear decommissioning trust fund investments				
Cash equivalents	245			245
Equity				
Individually held	1,480			1,480
Commingled funds		1,933		1,933
Equity funds subtotal	1,480	1,933		3,413
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	1,057			1,057
Debt securities issued by states of the United States and political subdivisions of the states		321		321
Debt securities issued by foreign governments		93		93
Corporate debt securities		1,788		1,788
Federal agency mortgage-backed securities		24		24
Commercial mortgage-backed securities (non-agency)		45		45
Residential mortgage-backed securities (non-agency)		11		11
Mutual funds		23		23
Fixed income subtotal	1,057	2,305		3,362
Middle market lending			183	183
Other debt obligations		15		15
Nuclear decommissioning trust fund investments subtotal(b)	2,782	4,253	183	7,218
Pledged assets for Zion Station decommissioning				
Cash equivalents		23		23
Equity				
Individually held	14			14
Commingled funds		9		9
Equity funds subtotal	14	9		23
Fixed income				
Debt securities issued by the U.S. Treasury and other U.S. government corporations and agencies	118	12		130
Debt securities issued by states of the United States and political subdivisions of the states		37		37
Corporate debt securities		249		249
Federal agency mortgage-backed securities		49		49
Commercial mortgage-backed securities (non-agency)		6		6
Fixed income subtotal	118	353		471
Middle market lending			89	89

Other debt obligations		1		1
Pledged assets for Zion Station decommissioning subtotal(c)	132	386	89	607
Rabbi trust investments				
Cash equivalents	1			1
Mutual funds(d)(e)	13			13
Rabbi trust investments subtotal	14			14

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity mark-to-market derivative assets				
Economic hedges	861	3,173	867	4,901
Proprietary trading	1,042	2,078	73	3,193
Effect of netting and allocation of collateral(f)	(1,823)	(4,175)	(58)	(6,056)
Commodity mark-to-market assets subtotal(g)	80	1,076	882	2,038
Interest rate mark-to-market derivative assets		101		101
Effect of netting and allocation of collateral		(51)		(51)
Interest rate mark-to-market derivative assets subtotal		50		50
Other investments	2		17	19
Total assets	3,497	5,765	1,171	10,433
Liabilities				
Commodity mark-to-market derivative liabilities				
Economic hedges	(1,041)	(2,289)	(169)	(3,499)
Proprietary trading	(1,084)	(1,959)	(78)	(3,121)
Effect of netting and allocation of collateral(f)	2,042	4,020	25	6,087
Commodity mark-to-market liabilities subtotal	(83)	(228)	(222)	(533)
Interest rate mark-to-market derivative liabilities		(84)		(84)
Effect of netting and allocation of collateral		51		51
Interest rate mark-to-market derivative liabilities		(33)		(33)
Deferred compensation		(28)		(28)
Total liabilities	(83)	(289)	(222)	(594)
Total net assets	$ 3,414	$ 5,476	$ 949	$ 9,839

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

(b) Excludes net assets of $21 million and $30 million at March 31, 2013 and December 31, 2012, 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 $5 million and $7 million at March 31, 2013 December 31, 2012, respectively. These items consist of receivables related to pending securities sales, interest and dividend receivables, and payables related to pending securities purchases.

(d) The $12 million mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

(e) Excludes $9 million and $8 million of the cash surrender value of life insurance investments at March 31, 2013 and December 31, 2012, respectively.

(f) Includes collateral postings (received) from counterparties. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $169 million, $64 million and $0 million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of

March 31, 2013. Collateral (received) from counterparties, net of collateral paid to counterparties, totaled $219 million, $(155) million and $(33) million allocated to Level 1, Level 2 and Level 3 mark-to-market derivatives, respectively, as of December 31, 2012.

(g) The Level 3 balance includes current and noncurrent assets for Generation of $85 million and $0 million at March 31, 2013 and $226 million and $0 million at December 31, 2012, respectively, related to the fair value of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013 and 2012:

Three Months Ended March 31, 2013	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2012	$ 183	$ 89	$ 660	$ 17	$ 949
Total realized / unrealized losses					
Included in net income	1		(144)(a)(b)		(143)
Included in other comprehensive income			(124)(b)		(124)
Included in noncurrent payables to affiliates	1				1
Change in collateral			33		33
Purchases, sales, issuances and settlements					
Purchases	32	22	(5)(c)		49
Sales	(7)	(7)	(4)	(8)	(26)
Transfers into Level 3			4		4
Transfers out of Level 3					
Balance as of March 31, 2013	$ 210	$ 104	$ 420	$ 9	$ 743
The amount of total losses included in income attributed to the change in unrealized gains (losses) related to assets and liabilities held for the three months ended March 31, 2013	$ 1	$	$ (86)	$	$ (85)

(a) Includes the reclassification of $58 million of realized losses due to the settlement of derivative contracts recorded in results of operations.
(b) Includes $8 million of increases in fair value and $133 million of realized losses due to settlements during 2013 of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $10 million which Generation was paid to enter into out of the money purchase contracts.

Three Months Ended March 31, 2012	Nuclear Decommissioning Trust Fund Investments	Pledged Assets for Zion Station Decommissioning	Mark-to-Market Derivatives	Other Investments	Total
Balance as of December 31, 2011	$ 13	$ 37	$ 817	$	$ 867
Total realized / unrealized losses					
Included in net income			74(a)		74
Included in other comprehensive income			(1)(b)		(1)
Change in collateral			(36)		(36)
Purchases, sales, issuances and settlements					
Purchases(c)		6	329	14	349
Sales		(1)			(1)
Transfers out of Level 3			(1)		(1)

Balance as of March 31, 2012	$	13	$	42	$	1,182	$	14	$	1,251
The amount of total gains included in income attributed to the change in unrealized gains related to assets and liabilities held for the three months ended March 31, 2012	$		$		$	93	$		$	93

(a) Includes the reclassification of $19 million of realized losses due to the settlement of derivative contracts recorded in results of operations.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

(b) Includes $135 million of increases in fair value and $147 million of realized losses due to settlements during 2012 of Generation s financial swap contract with ComEd, which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) Includes $323 million of fair value from contracts and $14 of other investments acquired as a result of the merger.

The following tables present the income statement classification of the total realized and unrealized gains (losses) included in income for Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013 and 2012:

	Operating Revenues	Purchased Power and Fuel
Total gains (losses) included in net income for the three months ended March 31, 2013	$ (176)	$ 32
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2013	$ (124)	$ 38

	Operating Revenues	Purchased Power and Fuel
Total gains (losses) included in net income for the three months ended March 31, 2012	$ 76	$ (2)
Change in the unrealized gains (losses) relating to assets and liabilities held for the three months ended March 31, 2012	$ 104	$ (11)

ComEd

The following tables present assets and liabilities measured and recorded at fair value on ComEd s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and December 31, 2012:

As of March 31, 2013	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Rabbi trust investments				
Mutual funds(a)	$ 7	$	$	$ 7
Rabbi trust investments subtotal	7			7
Total assets	7			7
Liabilities				
Deferred compensation obligation		(9)		(9)
Mark-to-market derivative liabilities(b)(c)			(160)	(160)
Total liabilities		(9)	(160)	(169)
Total net assets (liabilities)	$ 7	$ (9)	$ (160)	$ (162)

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 111	$	$	$ 111
Rabbi trust investments				
Mutual funds(a)	8			8
Rabbi trust investments subtotal	8			8
Total assets	119			119
Liabilities				
Deferred compensation obligation		(8)		(8)
Mark-to-market derivative liabilities(b)(c)			(293)	(293)
Total liabilities		(8)	(293)	(301)
Total net assets (liabilities)	$ 119	$ (8)	$ (293)	$ (182)

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.
(b) The Level 3 balance includes the current liability of $85 million at March 31, 2013, and $226 million at December 31, 2012, related to the fair value of ComEd s financial swap contract with Generation which eliminates upon consolidation in Exelon s Consolidated Financial Statements.
(c) The Level 3 balance includes the current and noncurrent liability of $15 million and $60 million at March 31, 2013, respectively, and $18 million and $49 million at December 31, 2012, respectively, related to floating-to-fixed energy swap contracts with unaffiliated suppliers.

The following tables present the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013 and 2012:

Three Months Ended March 31, 2013	Mark-to-Market Derivatives
Balance as of December 31, 2012	$ (293)
Total realized / unrealized gains included in regulatory assets(a)(b)	133
Balance as of March 31, 2013	$ (160)

(a) Includes $8 million of decreases in fair value and realized losses due to settlements of $133 million associated with ComEd s financial swap contract with Generation for the three months ended March 31, 2013. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.
(b) Includes $11 million of increases in the fair value and realized losses due to settlements of $3 million recorded in purchased power expense associated with floating-to-fixed energy swap contracts with unaffiliated suppliers for the three months ended March 31, 2013.

Three Months Ended March 31, 2012	Mark-to-Market Derivatives
Balance as of December 31, 2011	$ (800)
Total unrealized / realized losses included in regulatory assets(a)(b)	(23)
Balance as of March 31, 2012	$ (823)

(a) Includes $135 million of changes in the fair value and $147 million of realized gains due to settlements associated with ComEd s financial swap with Generation. All items eliminate upon consolidation in Exelon s Consolidated Financial Statements.

(b) Includes an increase in fair value of $35 million associated with floating-to-fixed energy swap contracts with unaffiliated suppliers.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

PECO

The following tables present assets and liabilities measured and recorded at fair value on PECO s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and December 31, 2012:

As of March 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 225	$	$	$ 225
Rabbi trust investments				
Mutual funds(a)(b)	9			9
Rabbi trust investments subtotal	9			9
Total assets	234			234
Liabilities				
Deferred compensation obligation		(18)		(18)
Total liabilities		(18)		(18)
Total net assets (liabilities)	$ 234	$ (18)	$	$ 216

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 346	$	$	$ 346
Rabbi trust investments				
Mutual funds(a)(b)	9			9
Rabbi trust investments subtotal	9			9
Total assets	355			355
Liabilities				
Deferred compensation obligation		(18)		(18)
Total liabilities		(18)		(18)
Total net assets (liabilities)	$ 355	$ (18)	$	$ 337

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets
(b) Excludes $14 million and $13 million of the cash surrender value of life insurance investments at March 31, 2013 and December 31, 2012, respectively.

PECO had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013.

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COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

BGE

The following tables present assets and liabilities measured and recorded at fair value on BGE s Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of March 31, 2013 and December 31, 2012:

As of March 31, 2013	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 58	$	$	$ 58
Rabbi trust investments				
Mutual funds(a)	5			5
Rabbi trust investments subtotal	5			5
Total assets	63			63
Liabilities				
Deferred compensation obligation		(5)		(5)
Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 63	$ (5)	$	$ 58

As of December 31, 2012	Level 1	Level 2	Level 3	Total
Assets				
Cash equivalents	$ 33	$	$	$ 33
Rabbi trust investments				
Mutual funds(a)	5			5
Rabbi trust investments subtotal	5			5
Total assets	38			38
Liabilities				
Deferred compensation obligation		(5)		(5)
Total liabilities		(5)		(5)
Total net assets (liabilities)	$ 38	$ (5)	$	$ 33

(a) The mutual funds held by the Rabbi trusts are classified as Level 1 as they are valued based upon quoted prices (unadjusted) in active markets.

BGE had no Level 3 assets or liabilities measured at fair value on a recurring basis during the three months ended March 31, 2013 and 2012.

Valuation Techniques Used to Determine Fair Value

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above.

Cash Equivalents (Exelon, Generation, ComEd, PECO and BGE). The Registrants cash equivalents include investments with maturities of three months or less when purchased. The cash equivalents shown in the fair value tables are comprised of investments in mutual and money market funds. The fair values of the shares of these funds are based on observable market prices and, therefore, have been categorized in Level 1 in the fair value hierarchy.

Nuclear Decommissioning Trust Fund Investments and Pledged Assets for Zion Station Decommissioning (Exelon and Generation). The trust fund investments have been established to satisfy Generation s nuclear decommissioning obligations as required by the NRC. The NDT funds hold debt and equity securities directly and indirectly through commingled funds. Generation s investment policies place limitations on the types and

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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investment grade ratings of the securities that may be held by the trusts. These policies limit the trust funds exposures to investments in highly illiquid markets and other alternative investments. Investments with maturities of three months or less when purchased, including certain short-term fixed income securities are considered cash equivalents and included in the recurring fair value measurements hierarchy as Level 1.

With respect to individually held equity securities, the trustees obtain prices from pricing services, whose prices are obtained from direct feeds from market exchanges, which Generation is able to independently corroborate. The fair values of equity securities held directly by the trust funds are based on quoted prices in active markets and are categorized in Level 1. Equity securities held individually are primarily traded on the New York Stock Exchange and NASDAQ-Global Select Market, which contain only actively traded securities due to the volume trading requirements imposed by these exchanges.

For fixed income securities, multiple prices from pricing services are obtained whenever possible, which enables cross-provider validations in addition to checks for unusual daily movements. A primary price source is identified based on asset type, class or issue for each security. The trustees monitor prices supplied by pricing services and may use a supplemental price source or change the primary price source of a given security if the portfolio managers challenge an assigned price and the trustees determine that another price source is considered to be preferable. Generation has obtained an understanding of how these prices are derived, including the nature and observability of the inputs used in deriving such prices. Additionally, Generation selectively corroborates the fair values of securities by comparison to other market-based price sources. U.S. Treasury securities are categorized as Level 1 because they trade in a highly liquid and transparent market. The fair values of fixed income securities, excluding U.S. Treasury securities, are based on evaluated prices that reflect observable market information, such as actual trade information or similar securities, adjusted for observable differences and are categorized in Level 2.

Equity and fixed income commingled funds and fixed income mutual funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives. The fair values of fixed income commingled and mutual funds held within the trust funds, which generally hold short-term fixed income securities and are not subject to restrictions regarding the purchase or sale of shares, are derived from observable prices. The objectives of the remaining equity commingled funds in which Exelon and Generation invest primarily seek to track the performance of certain equity indices by purchasing equity securities to replicate the capitalization and characteristics of the indices. In general, equity commingled funds are redeemable on the 15th of the month and the last business day of the month; however, the fund manager may designate any day as a valuation date for the purpose of purchasing or redeeming units. Commingled and mutual funds are categorized in Level 2 because the fair value of the funds are based on NAVs per fund share (the unit of account), primarily derived from the quoted prices in active markets on the underlying equity securities. See Note 12 Nuclear Decommissioning for further discussion on the NDT fund investments.

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

Rabbi Trust Investments (Exelon, Generation, ComEd, PECO and BGE). The Rabbi trusts were established to hold assets related to deferred compensation plans existing for certain active and retired members of Exelon s executive management and directors. The investments in the Rabbi trusts are included in investments in the Registrants Consolidated Balance Sheets. The investments are in fixed-income commingled funds and

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mutual funds, including short-term investment funds. These funds are maintained by investment companies and hold certain investments in accordance with a stated set of fund objectives, which are consistent with Exelon s overall investment strategy. The values of some of these funds are publicly quoted. For fixed-income commingled funds and mutual funds which are not publicly quoted, the fund administrators value the funds using the net asset value per fund share, derived from the quoted prices in active markets of the underlying securities. These funds have been categorized as Level 2. Fixed-income commingled funds and mutual funds which are publicly quoted, such as money market funds, have been categorized as Level 1 given the clear observability of the prices.

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

Exelon may utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to achieve its targeted level of variable-rate debt as a percent of total debt. In addition, the Registrants may utilize interest rate derivatives to lock in interest rate levels in anticipation of future financings. These interest rate derivatives are typically designated as cash flow hedges. Exelon determines the current fair value by calculating the net present value of expected payments and receipts under the swap agreement, based on and discounted by the market s expectation of future interest rates. Additional inputs to the net present value calculation may include the contract terms, counterparty credit risk and other market parameters. As these inputs are based on observable data and valuations of similar instruments, the interest rate swaps are categorized in Level 2 in the fair value hierarchy. See Note 9 Derivative Financial Instruments for further discussion on mark-to-market derivatives.

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

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

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

Disclosed below is detail surrounding the Registrants significant Level 3 valuations. The most significant position is the long term intercompany swap with ComEd, which is further discussed in Note 9 Derivative Financial Instruments. The calculated fair value includes marketability discounts for margining provisions and notional size. Generation s remaining Level 3 balance generally consists of forward sales and purchases of power and natural gas, coal purchases, transmission congestion contracts, and project financing debt. Generation utilizes various inputs and factors including market data and assumptions that market participants would use in pricing assets or liabilities as well as assumptions about the risks inherent in the inputs to the valuation technique. The inputs and factors include forward commodity prices, commodity price volatility, contractual volumes, delivery location, interest rates, credit quality of counterparties and credit enhancements.

For commodity derivatives, the primary input to the valuation models is the forward commodity price curve for each instrument. Forward commodity price curves are derived by risk management for liquid locations and by the traders and portfolio managers for illiquid locations. All locations are reviewed and verified by risk management considering published exchange transaction prices, executed bilateral transactions, broker quotes, and other observable or public data sources. The relevant forward commodity curve used to value each of the derivatives depends on a number of factors, including commodity type, delivery location, and delivery period. Price volatility varies by commodity and location. When appropriate, Generation discounts future cash flows using risk free interest rates with adjustments to reflect the credit quality of each counterparty for assets and Generation s own credit quality for liabilities. The level of observability of a forward commodity price is generally due to the delivery location and delivery period. Certain delivery locations including PJM West Hub (for power) and Henry Hub (for natural gas) are highly liquid and prices are observable for up to three years in the future. The observability period of volatility is generally shorter than the underlying power curve used in option valuations. The forward curve for a less liquid location is estimated by using the forward curve from the liquid location and applying a spread to represent the cost to transport the commodity to the delivery location.

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This spread does not typically represent a majority of the instrument s market price. As a result, the change in fair value is closely tied to liquid market movements and not a change in the applied spread. The change in fair value associated with a change in the spread is generally immaterial. An average spread calculated across all Level 3 power and gas delivery locations is generally less than $2.50 and $0.15 for power and natural gas, respectively. Many of the commodity derivatives are short term in nature and thus a majority of the fair value may be based on observable inputs even though the contract as a whole must be classified as Level 3. See ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK for information regarding the maturity by year of the Registrant s mark-to-market derivative assets and liabilities.

On December 17, 2010, ComEd entered into several 20-year floating to fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. See Note 9 Derivative Financial Instruments for more information. The fair value of these swaps has been designated as a Level 3 valuation due to the long tenure of the positions and internal modeling assumptions. The modeling assumptions include using natural gas heat rates to project long term forward power curves adjusted by a renewable factor that incorporates time of day and seasonality factors to reflect accurate renewable energy pricing. In addition, marketability reserves are applied to the positions based on the tenor and supplier risk. The table below discloses the significant inputs to the forward curve used to value these positions.

Type of trade	Fair Value at March 31, 2013(d)	Valuation Technique	Unobservable Input	Range
Mark-to-market derivatives Economic Hedges (Generation)(a)	$ 346	Discounted Cash Flow	Forward power price	$14 - $88
			Forward gas price	$3.43 - $4.73
		Option Model	Volatility percentage	28% - 177%
Mark-to-market derivatives Proprietary trading (Generation)(a)	$ (11)	Discounted Cash Flow	Forward power price	$16 - $88
		Option Model	Volatility percentage	14% - 34%
Mark-to-market derivatives Transactions with affiliates (Generation and ComEd)(b)	$ 85	Discounted Cash Flow	Marketability reserve	7% - 8%
Mark-to-market derivatives (ComEd)	$ (75)	Discounted Cash Flow	Forward heat rate(c)	8.5% - 9.5%
			Marketability reserve	3.5% - 8.3%
			Renewable factor	85% - 128%

a) The valuation techniques, unobservable inputs and ranges are the same for the asset and liability positions.
b) Includes current assets for Generation and current liabilities for ComEd of $85 million, related to the fair value of the five-year financial swap contract between Generation and ComEd, which eliminates in consolidation.
c) Quoted forward natural gas rates are utilized to project the forward power curve for the delivery of energy at specified future dates. The natural gas curve is extrapolated beyond its observable period to the end of the contract s delivery.
d) The fair values do not include cash collateral held on level three positions which are immaterial as of March 31, 2013.

The inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. The significant unobservable inputs used in the fair value measurement of Generation s commodity

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

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

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

As of March 31, 2013, Generation has outstanding commitments to invest in middle market lending of approximately $186 million. These commitments will be funded by Generation s existing nuclear decommissioning trust funds.

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

The Registrants are exposed to certain risks related to ongoing business operations. The primary risks managed by using derivative instruments are commodity price risk and interest rate risk.

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

To the extent the amount of energy Exelon generates differs from the amount of energy it has contracted to sell, the Registrants are exposed to market fluctuations in the prices of electricity, fossil fuels and other commodities. The Registrants employ established policies and procedures to manage their risks associated with market fluctuations by entering into physical and financial derivative contracts including swaps, futures, forwards, options and short-term and long-term commitments to purchase and sell energy and energy-related products. The Registrants believe these instruments, which are classified as either economic hedges or non-derivatives, mitigate exposure to fluctuations in commodity prices.

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Derivative accounting guidance requires that derivative instruments be recognized as either assets or liabilities at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation, provided they meet specific, restrictive criteria both at the time of designation and on an ongoing basis. These alternative permissible accounting treatments include normal purchase normal sale (NPNS), cash flow hedge, and fair value hedge. For commodity transactions, effective with the date of merger with Constellation, Generation no longer utilizes the special election provided for by the cash flow hedge designation and de-designated all of its existing cash flow hedges prior to the merger. Because the underlying forecasted transactions remain at least reasonably possible, the fair value of the effective portion of these cash flow hedges was frozen in accumulated OCI and will be reclassified to results of operations when the forecasted purchase or sale of the energy commodity occurs, or becomes probable of not occurring. None of Constellation s designated cash flow hedges for commodity transactions prior to the merger were re-designated as cash flow hedges. The effect of this decision is that all derivative economic hedges for commodities are recorded at fair value through earnings for the combined company, referred to as economic hedges in the following tables. The Registrants have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements, and natural gas supply agreements. Non-derivative contracts for access to additional generation and certain sales to load-serving entities are accounted for primarily under the accrual method of accounting, which is further discussed in Note 19 Commitments and Contingencies of the Exelon 2012 Form 10-K. Additionally, Generation is exposed to certain market risks through its proprietary trading activities. The proprietary trading activities are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s overall energy marketing activities.

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

In general, increases and decreases in forward market prices have a positive and negative impact, respectively, on Generation s owned and contracted generation positions that have not been hedged. Generation hedges commodity price risk on a ratable basis over three-year periods. As of March 31, 2013, the percentage of expected generation hedged for the major reportable segments was 98%-101%, 70%-73%, and 33%-36% for 2013, 2014, and 2015, respectively. The percentage of expected generation hedged is the amount of equivalent sales divided by the expected generation. Expected generation represents the amount of energy estimated to be generated or purchased through owned or contracted capacity. Equivalent sales represent all hedging products, which include economic hedges and certain non-derivative contracts including, Generation s sales to ComEd, PECO and BGE to serve their retail load.

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ComEd has locked in a fixed price for a significant portion of its commodity price risk through the five-year financial swap contract with Generation that expires on May 31, 2013, which is discussed in more detail below. In addition, the physical contracts that Generation has entered into with ComEd and that ComEd has entered into with Generation and other suppliers as part of the ComEd power procurement process, which are further discussed in Note 3 Regulatory Matters of the Exelon 2012 Form 10-K, qualify and are accounted for under the NPNS exception. Based on the Illinois Settlement Legislation and ICC-approved procurement methodologies permitting ComEd to recover its electricity procurement costs from retail customers with no mark-up, ComEd s price risk related to power procurement is limited.

In order to fulfill a requirement of the Illinois Settlement Legislation, Generation and ComEd entered into a five-year financial swap contract effective August 28, 2007. The financial swap is designed to hedge spot market purchases, which, along with ComEd s remaining energy procurement contracts, meet its load service requirements. The remaining swap contract volume is 3,000 MWs through May 2013. The terms of the financial swap contract require Generation to pay the around-the-clock market price for a portion of ComEd s electricity supply requirement, while ComEd pays a fixed price. The contract is to be settled net, for the difference between the fixed and market pricing, and the financial terms only cover energy costs and do not cover capacity or ancillary services. The financial swap contract is a derivative financial instrument that was originally designated by Generation as a cash flow hedge. As discussed previously, effective with the date of merger with Constellation, Generation de-designated this swap as a cash flow hedge and began recording changes in fair value through current earnings as of that date. Generation records the fair value of the swap on its balance sheet and originally recorded changes in fair value to OCI. The value frozen in OCI as of the date of merger for this swap is reclassified into Generation s earnings as the swap settles. ComEd has not elected hedge accounting for this derivative financial instrument. Since the financial swap contract was deemed prudent by the Illinois Settlement Legislation, ComEd receives full cost recovery for the contract in rates and, therefore, the change in fair value each period is recorded as a regulatory asset or liability on ComEd s Consolidated Balance Sheets. See Note 3 Regulatory Matters of the Exelon 2012 Form 10-K for additional information regarding the Illinois Settlement Legislation. In Exelon s consolidated financial statements, all financial statement effects of the financial swap recorded by Generation and ComEd are eliminated.

On December 17, 2010, ComEd entered into several 20-year floating-to-fixed energy swap contracts with unaffiliated suppliers for the procurement of long-term renewable energy and associated RECs. Delivery under the contracts began in June 2012. Pursuant to the ICC s Order on December 19, 2012, ComEd s commitments under the existing long-term contracts for energy and associate RECs were reduced in the first quarter of 2013. These contracts are designed to lock in a portion of the long-term commodity price risk resulting from the renewable energy resource procurement requirements in the Illinois Settlement Legislation. ComEd has not elected hedge accounting for these derivative financial instruments. ComEd records the fair value of the swap contracts on its balance sheet. Because ComEd receives full cost recovery for energy procurement and related costs from retail customers, the change in fair value each period is recorded by ComEd as a regulatory asset or liability. See Note 5 Regulatory Matters for additional information.

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

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PECO s natural gas procurement policy is designed to achieve a reasonable balance of long-term and short-term gas purchases under different pricing approaches in order to achieve system supply reliability at the least cost. PECO s reliability strategy is two-fold. First, PECO must assure that there is sufficient transportation capacity to satisfy delivery requirements. Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources. All of PECO s natural gas supply and asset management agreements that are derivatives either qualify for the normal purchases and normal sales scope exception and have been designated as such, or have no mark-to-market balances because the derivatives are index priced. Additionally, in accordance with the 2012 PAPUC PGC settlement and to reduce the exposure of PECO and its customers to natural gas price volatility, PECO has continued its program to purchase natural gas for both winter and summer supplies using a layered approach of locking-in prices ahead of each season with long-term gas purchase agreements (those with primary terms of at least twelve months). Under the terms of the 2012 PGC settlement, PECO is required to lock in (i.e., economically hedge) the price of a minimum volume of its long-term gas commodity purchases. PECO s gas-hedging program is designed to cover about 30% of planned natural gas purchases in support of projected firm sales. The hedging program for natural gas procurement has no direct impact on PECO s financial position or results of operations as natural gas costs are fully recovered from customers under the PGC.

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

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

Proprietary Trading. Generation also enters into certain energy-related derivatives for proprietary trading purposes. Proprietary trading includes all contracts entered into with the intent of benefiting from shifts or changes in market prices as opposed to those entered into with the intent of hedging or managing risk. Proprietary trading activities are subject to limits established by Exelon s RMC. The proprietary trading activities, which included settled physical sales volumes of 1,572 GWhs and 1,888 GWhs for the three months ended March 31, 2013 and 2012, respectively, are a complement to Generation s energy marketing portfolio but represent a small portion of Generation s revenue from energy marketing activities. ComEd, PECO and BGE do not enter into derivatives for proprietary trading purposes.

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

The Registrants use a combination of fixed-rate and variable-rate debt to manage interest rate exposure. The Registrants may also utilize fixed-to-floating interest rate swaps, which are typically designated as fair value hedges, as a means to manage their interest rate exposure. In addition, the Registrants may utilize interest rate

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derivatives to lock in rate levels in anticipation of future financings, which are typically designated as cash flow hedges. These strategies are employed to manage interest rate risks. At March 31, 2013, Exelon had $800 million of notional amounts of fixed-to-floating hedges outstanding and $394 million of notional amounts of floating-to-fixed hedges outstanding. Assuming the fair value and cash flow interest rate hedges are 100% effective, a hypothetical 50 bps increase in the interest rates associated with unhedged variable-rate debt (excluding Commercial Paper and PECO Accounts Receivables Facility) and fixed-to-floating swaps would result in less than $ 1 million decrease in Exelon Consolidated pre-tax income for the three months ended March 31, 2013. Below is a summary of the interest rate hedges as of March 31, 2013.

	Generation					Other	Exelon
Description	**Derivatives Designated as Hedging Instruments**	**Economic Hedges**	**Proprietary Trading (a)**	**Collateral and Netting (b)**	**Subtotal**	**Derivatives Designated as Hedging Instruments**	**Total**
Mark-to-market derivative assets (Current Assets)	$	$ 3	$				